S. Hrg. 99-253

ELECTRIC POWER: POTENTIAL FOR SHORTAGES IN THE 1990's

HEARINGS

BEFORE THE

COMMITTEE ON
ENERGY AND NATURAL RESOURCES
UNITED STATES SENATE

NINETY-NINTH CONGRESS

FIRST SESSION

ON THE

POTENTIAL FOR SERIOUS REGIONAL SHORTAGES OF ELECTRIC POWER
IN THE UNITED STATES BY THE EARLY 1990'S

JULY 23 AND 25, 1985

Printed for the use of the
Committee on Energy and Natural Resources

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ELECTRIC POWER: POTENTIAL FOR SHORTAGES IN THE 1990's

TUESDAY, JULY 23, 1985

U.S. Senate,
Committee on Energy and Natural Resources,
Washington, DC.

The committee met, pursuant to notice, at 9:33 a.m., in room SD-366, Dirksen Office Building, Hon. James A. McClure, chairman, presiding.

Present: Senators McClure, Warner, Hecht, Evans, Johnston, Bumpers, Ford, Metzenbaum, Bradley, and Rockefeller.

Also present: E. David Doane, senior counsel; Elizabeth Moler, counsel for the minority; and Benjamin S. Cooper, professional staff member for the minority.

OPENING STATEMENT OF HON. JAMES A. McCLURE, A U.S. SENATOR FROM THE STATE OF IDAHO

The Chairman. The committee will come to order.

The primary purpose of this 2-day hearing is to take a long, hard look at whether this country will be confronted with regional shortages of electric power in the early 1990's.

This is a question of more than mere academic interest. If we find that shortages are likely to occur on some utility systems, then we must face up to the fact that the problem is an immediate one. We must begin to deal with it now, not when the shortages actually appear.

During the course of this hearing, we will also be asking questions about the basic assumptions used in the forecast of demand for electric power. Those assumptions include such subjects as conservation, cogeneration, imported power from Canada, and the voluntary wheeling of power.

In addition, we will be discussing some of the fundamental problems facing the electric utility industry such as the environmental uncertainties surrounding coal-fired generation, the licensing delays that afflict nuclear power, and the reactions of the State regulatory commissions to public concerns about escalating electric bills.

There are two issues that, in my judgment, merit the particular attention of this committee. One involves demand for electricity, and the other relates to supply. First, if we ask what the demand for electricity will be 5 years from now, we find that there is wide disagreement among the experts who make the forecasts. Some bluntly say that the potential for future electric power shortages is a mirage because the growth in demand will be very low. What if they are wrong? What price will electric consumers pay? These questions point to the basic issue of whether utilities and consumers can afford to assume the risk of underestimating future demand.

The second issue involves the ability of electric utility companies to supply the amount of new generating capacity needed to meet future demand at whatever level it may be. Electric utilities today seem to be confronted by a long line of barriers that have the effect of inhibiting construction of new generating plants. In recent years, these barriers have grown in number and size. They are placed at every stage of the planning and construction process, and they effect every type of generating plant. The barriers consist of regulatory constraints at all levels of government, environmental restrictions, a variety of financial limitations, and the overriding risk of abrupt and unanticipated changes in government policies of all of these areas at any time.

Taken together, these barriers may have grown to the point that the added costs and risks of building new generating capacity are simply unacceptable to utilities. That is the thesis of a number of electric utility analysts, who emphasize the adverse effects of the changing regulatory climate at the State level.

In some States where utilities have recently completed construction of large generating plants, the added capacity turned out to be too much because system demand had not grown at the rate forecasted years earlier when the decision to build the plants was made. The public utility commissions in a number of these States have concluded that if a portion of the capacity of a new plant is not needed, then the ratepayers should not have to pay for it.

The result, according to some financial analysts, has been a form of severe economic penalty imposed on electric utilities when they overestimate demand. The argument is that the risk of miscalculating demand has been shifted from the ratepayers to the stockholders.

This is an important issue, because it has a direct bearing on the question of whether the supply of baseload generating capacity will be adequate during the next decade.

Finally, I would suggest that we need to look carefully at the options available to utilities if they find that their generating capacity will not meet the demand on their systems. Will they be able to use gas-fired combustion turbines? That will depend in part on whether adequate supplies of gas will be available.

Will they be able to purchase the extra power from other companies? That will depend, of course, on whether other utilities have excess power available for sale and whether the transmission facilities are adequate. Assuming that a utility can obtain additional supplies by using gas turbines or by purchasing power, what will be the added cost to the ratepayers, and how will it compare to the cost that would have been incurred if new baseload capacity had been constructed and brought on line when it was needed?

There are no definitive answers to those questions, but that should not prevent us from attempting to make the best possible judgments.

As the starting point, the committee today will receive testimony from economic forecasters, electric utility executives, and State regulatory commissioners. On the second day of the hearing, we will hear from two other groups of forecasters and a number of other witnesses representing various segments of the electric utility industry.

At this point in the record we will insert the statement of the Honorable Senator J. Bennett Johnston, the ranking Democratic member of this committee.

[The prepared statement of Senator Johnston follows:]

Statement of Senator J. Bennett Johnston

Hearings on Potential Shortages of Electricity
July 23, 1985

I want to congratulate the Chairman for holding these hearings. The electricity supply and demand issues we will be discussing are vitally important to the economy, well being and quality of life in the United States. And these issues are almost totally misunderstood by the American public.

Moreover, I do not believe that the policymakers in Washington and in the State capitals are even close to appreciating the magnitude of the problem they are facing.

We have stopped constructing central station electric generating capacity in this country, and all the forces that act on utility executives tend to keep things that way. In truth, electric utilities have lost the ability and perhaps the incentive to control their destiny.

The result of this will be an electric system that is still a regulated monopoly, but one without an effective planning function.

We are spreading the opportunities to make decisions about new capacity to others, but leaving the risks of shortages with the utilities. In the face of this risk they are hunkering down, refusing to act, guaranteeing that shortages will occur, if not in this decade, surely in the next.

The proper aim of this hearing is to identify those aspects of this very complex problem that lend themselves to Federal influence. We should be asking not only what the problem is, but what we should be doing about it.

Mr. Chairman, I ask that two speeches I recently gave on this subject be inserted in the hearing record at the end of these remarks.

Electricity 2000

Senator J. Bennett Johnston

Remarks to the
Southeastern Electric Exchange
Boca Raton, Florida
March 25, 1985

Today I want you to join me in thinking through the implications of an outrageous notion: suppose what many people are warning us about the future of the electricity business actually happens?

Imagine what the world will be like in the year 2000 in the electricity business if current trends simply continue. Suppose the nation just keeps on doing what it is now doing. Assume the projections we have about electricity demand in the 1980's and 1990's are true. What does this imply about life in the year 2000?

David Stockman and Ronald Reagan are projecting economic growth at 4.0 percent for most of this decade. Electricity demand grows when GNP grows. The Energy Information Administration says electricity demand grows at 1.2 times the rate that GNP grows. So the Administration's economic forecast implies electricity demand will grow at more than 4 percent per year.

According to the Office of Technology Assessment, at 3.5 percent electricity demand growth, you have to add the equivalent of about 300 thousand megawatt plants that are not now in anyone's plans. At 4 percent you have to add about 400 such plants. You have to add these plants to meet demand in 2000 with a reserve margin of 20 percent, which is what everyone thinks is the minimum to cover peaking demand and outages for maintenance.

In the year 2000 we expect that total electric capacity will be about 1000 million kilowatts, or the equivalent of around 1000 of these plants. So 200 plants is the reserve margin. If we get to the year 2000 without the 400 new plants we need, there will be no reserve margin, and a shortage of 20% in base load demand.

On any given day, the system will be unable to supply the demand. What does this mean?

It means a choice between rotating blackouts and the rationing of electricity - or what you would call "enforced load management".

Since there wouldn't be enough electricity to go around, someone would have to decide who gets served. Who's first? Factories or farmers? Homes or hospitals? Employment or government?

The first casualty is predictable. It would be economic growth. Or, more probably, economic health.

And what of comfort? Air conditioning is considered a necessity in my part of the world. And we've gotten used to the electric light. But we know that in developing countries where electricity supply is inadequate, one of the favorite "load management" techniques is the rolling blackout. On two hours, off two hours.

It is hard to imagine just how bad the political fallout from this personal and economic misery would be. I think it would be very bad. If the energy crisis of the 1970's became the moral equivalent of war, the capacity shortfall of the 1990's would be the moral equivalent of political revolution.

It would provoke a political reaction of a kind, quality, and intensity that has never been known in this country.

Why have we avoided shortages in electricity supplies all these years? Electric capacity has been added at predictable cost -- predictable cost of capital, predictable cost to construct the plant, predictable (and short) construction times, predictable cost to obtain the fuel, predictable regulatory treatment for the output.

Most importantly, it was profitable to construct new generating capacity. New plant was more efficient than old plant. New plant lowered output costs on a per unit basis. Profits went up. The main job of the regulator was to step in and order lower rates to match the lower costs so that the "windfall" from new, more efficient facilities could be transferred from the utility to the consumer.

There was no capacity shortage. Overcapacity was not considered a problem by anyone except the few environmentalists who opposed -- in unsophisticated and ineffective ways -- construction of any new powerplant.

And what about the potential shortfall in capacity that I have described? I can hear the arguments. "It couldn't happen in the U.S. The free market would signal the shortage long before it occurred. The market would elicit the necessary supply. And if the market didn't perform the task, the government would step in with pump-priming incentives, economic blandishments. This is the way it has always been."

My thesis is that things have fundamentally changed, that the system is not working now, and it won't work in the future unless we change it.

In the good old days being a utility executive was a comfortable, if not a challenging job. You couldn't go broke. You could hardly fail to make money.

Today things are profoundly different. Everything that was once predictable is now unpredictable.

Demand growth is unpredictable. If you believed and acted upon the standard historical projection of 8 percent per year electricity demand growth, you may now be threatened with bankruptcy. Today we are arguing about whether electricity demand will grow at 2, or 3, or 4, or 5 percent, more or less.

Interest rates, that were stable for so long, went from 4.5 percent in 1965 to 18.9 percent in 1981. Do we know what interest rates will be over the next fifteen years?.

Inflation, that was so low and so stable for so long, went from 1.7 percent in 1965 to 13.5 percent in 1980. Do you want to bet on what inflation will do over the next fifteen years?

There is only one thing that is predictable: the new plants that you do bring on line will cost more than the plants you have. The new plants will raise your unit costs.

Not the least of the unpredictabilities you face is the unpredictability - even the perversity - of regulation.

The problem, of course, was not limited to unpredictability in demand, interest rates, inflation, and construction costs. The cruelest blow of all to the nuclear industry, and hence to the utility industry, was the change in policy towards nuclear power between 1970 and the end of the decade. Federal regulation of nuclear power during the 1970's - with a big assist from Three Mile Island - changed from relatively straightforward oversight of an industry to a highly legalistic, confrontation-prone, adversarial, paper chasing, lawyer's delight, the principal manifestation of which was the increase in the time of construction of a nuclear powerplant from 6 years to 12 years.

You hear good noises from your friends - like me - about solutions to the uncertainties of regulation: standard designs, site banking, limitations on backfitting, less adversarial proceedings. But we all know that uncertainty at least in the near term is a certainty.

The principal alternative to nuclear power - coal - has only slightly less serious problems than nuclear power. The environmental insult of direct coal combustion is real and serious, and the methods of mitigation are expensive. Only one coal plant has been ordered in the last three years. The time for construction of a new coal-fired powerplant is 8 years, better, but not that much better, than the 12 years it takes on average to bring a new nuclear powerplant on line.

Don't bet too much on being saved from an electricity capacity crunch in the 1990's by coal plants. We have yet to see the strength of the opposition to lots of new coal plants. We have yet to assess the environmental constraints coal will have to live with.

So, what happens to a public utility that, innocently I believe in most cases, got caught in this unpredictability? What happens when you can't afford to finish a very expensive plant? Or when you are forced to bring such a plant on line at several times its originally-estimated cost?

We don't know the full answer - the courts and the public utility commissions are just now beginning to decide these issues in their many variations. But it is clear that some courts and some public utility commissions will not allow the full recovery of costs. This will mean varying degrees of disaster, from bankruptcy to watering down of stockholders equity to triple-B bond ratings to other unpalatable remedies we do not now even know of.

What is going to be the political atmosphere in which these decisions will be made? Decidedly hostile.

Let me tell you a little about what's happening in my State.

I've made a preliminary survey of utility residential rate projections for the major investor-owned and publicly-operated utilities in Louisiana. The results are that by 1990 rates will be approximately four times the rates of 1975. More specifically, in the next five years rates will go up by 50 to 80 percent.

While I don't have the specific data outside Louisiana, I believe the trend holds true nationwide.

Today's political bonfire will be tomorrow's political firestorm. Everyone in elected office, especially including public service commissioners, will have to deal with the avalanche of protest that is coming.

What this reaction will mean is clear. It will be very difficult to adopt sensible policies for electric utilities. Those who have been friends of the industry will be less vocal where utility problems are concerned. Those who have not been friends of the industry will find it much easier to criticize utilities, to impose more onerous regulations, and to defeat legislation designed to help solve the problem.

The impact of an unfavorable political climate is much larger than most people realize. When the public turns hostile, the hostility shows up everywhere.

Court cases that might have been won are settled at a loss. Court cases that go to judgment more often go against you, with larger, more damaging penalties.

Regulators become actively hostile in matters large and small. The options under consideration in solving regulatory problems all become suddenly unfavorable.

Let me restate the danger from a different perspective - that of a prudent utility executive, which you all are, here assembled. As you contemplate the decision to construct a new plant, what are the consequences that attach to a wrong decision?

If you don't build the plant, but you needed to, you contribute to the national shortfall, economic growth is stymied in your service area, and you are roundly cursed by the media and the public. But your company can sell all the electricity it can generate. And the economic health of your company is assured.

If you do build the plant and are wrong for any one or a combination of the many ways you could be wrong, the consequences mean bankruptcy for your company and unemployment for you.

I'm quite sure each of you has figured this out for yourself, and that is why no new nuclear plant has been ordered since 1978 and 108 have been cancelled. That is why there has been only one central station coal plant ordered in the last three years. It is why utility executives across the country will, in my judgment, err seriously in the direction of no new construction.

And, combine this with the public hostility generated by the rate increases of the next half decade, and you have the reason that government is unlikely to do anything constructive to alleviate the problem.

Given the lead time necessary for new plants, our scenario for the year 2000 is altogether possible and believable - that is, unless a the very lack of electric generating capacity inhibits the economic growth forseen by this Administration.

I do not believe that this scenario is inevitable. I do not believe that there is nothing we can do to avoid it.

I suggest three things:

First, utilities must become more engaged politically. This means public education, telling the public what is happening to rates, why it is happpening and what they will be faced with. It means educating public officials and learning much more about how these officials are likely to behave, and why they are likely to behave that way. It means direct and much more active involvement in political campaigns.

Second, there is a shopping list of things that can be done in the near term and that we can all agree will help, if they cannot solve the long term problem:

(1) repeal the provision of the Fuel Use Act that outlaws new gas-fired powerplants. We've got the gas and there is no reason to arbitrarily restrict utilities' generating options.

(2) let utilities own cogeneration facilities. Utilities need to be more involved in how ths potential source of power is used.

(3) demonstrate new clean coal-burning technologies that can be implemented in existing dirty coal-burning facilities. Coal needs to be a big part of U. S. generation, and acid rain restrictions could threaten that. The best answer to acid rain is new clean-burning technology. There are promising technologies, but they need to be demonstrated at near commercial scale.

Third, on the Federal policy level, begin to take some of the uncertainty out of deciding whether or not to build new powerplants, coal or nuclear.

For coal, adopt reasonable rules for acid rain control so the industry knows what it has to do. Perhaps we're not ready to settle the acid rain question because we don't know enough about acid rain. But sooner or later we ought to decide finally and definitely. Uncertainty is a big problem in itself.

We must decide what we intend to do with nuclear power.

I think the decision should be - and I hope it will be - to proceed with nuclear power. I believe it is demonstrably the safest and most environmentally acceptable form of electrical energy generation.

The nuclear industry in the rest of the world is alive and well. In France and in Japan it takes about 6 years to build a nuclear powerplant. If you could count on that kind of schedule and their kind of regulatory atmosphere, many of your negative decisions would become positive decisions.

We ought therefore to determine how it is that they are so successful while we fail. Are their plants as safe as ours? Do they cut corners on environmental protection?

Or is the problem something else. Is it that in our litigous, legalistic, adversarial, procedure conscious, publicly debating and hearing society, the fortunate state of affairs that prevails in these countries cannot be achieved? We haven't really even asked that question.

One of the great phenomona of the last decade is the emergence of Japan as great force in international trade, leaving long dominant American industries baffled as to how the Japanese got ahead. One of the clear answers is that the Japanese government and Japanese industry, acting together, identified problems and opportunities for the long term and prepared for them.

While America was concerned with next quarter's profit and this year's dividend, Japan was planning new productive capacity with new technology that would dominate the coming decade.

That is America's problem in electricity writ large. Utility executives are worried about survival, how to get through this year's crisis. Public utility commissions are worried about the effect of this year's rate increase on next year's election. And in Washington we are not tuned into this problem at all.

In the back of everyone's mind is the thought that the invisible hand of the free enterprise system will somehow reach in and make everything work out for the best.

I am sorry to say that I do not believe that things are going to work out for the best automatically. Quite the contrary. I believe that the potential for serious trouble is real; that very few of the important decisionmakers are aware of the dimensions of the problem; that all the built-in forces that act through the economic, regulatory and political systems will push in the direction of making the problem worse.

Our current political leadership likes to talk about limiting the role of government in the economy and relying on private sector leadership. The utilities' problems need some government leadership.

Our task is to demand that leadership and, finally, begin the movement that will turn this situation around.

NUCLEAR POWER IN THE UNITED STATES

REMARKS BY UNITED STATES SENATOR J. BENNETT JOHNSTON
TO THE NUCLEAR POWER ASSEMBLY, WASHINGTON, D.C.

MAY 7, 1985

ALL OVER THE WORLD NUCLEAR ENERGY IS A LOW-COST, SECURE, ENVIRONMENTALLY ACCEPTABLE FORM OF ENERGY -- EVERYWHERE EXCEPT IN THE UNITED STATES. IN THE UNITED STATES, CIVILIAN NUCLEAR POWER IS, IF NOT DEAD, IN A DEEP COMA.

IN THE UNITED STATES, 112 NUCLEAR PLANTS HAVE BEEN ABANDONED OR CANCELLED IN THE LAST DECADE. THERE HAVE BEEN NO NEW ORDERS FOR NUCLEAR PLANTS SINCE 1978, WHEN THERE WERE TWO. ALL THE NUCLEAR PLANTS ORDERED BETWEEN 1974 AND 1977 HAVE BEEN CANCELLED. WE ONCE TALKED OF SEVERAL HUNDRED NUCLEAR PLANTS IN OPERATION BY THE YEAR 2000. WE NOW THINK WE WILL BE FORTUNATE TO HAVE 125 OPERATING NUCLEAR PLANTS IN THE UNITED STATES IN THE YEAR 2000.

THERE ARE 94 NUCLEAR POWER PLANTS IN THE UNITED STATES TODAY WITH LICENSES TO OPERATE. HALF THAT MANY ARE UNDER CONSTRUCTION. SEVERAL OF THOSE UNDER CONSTRUCTION WILL EVENTUALLY BE ABANDONED. EVEN SO, THE PROSPECT FOR THE YEAR 2000 IS THAT NUCLEAR ENERGY WILL PROVIDE ABOUT 20 PERCENT OF U.S. ELECTRICITY GENERATION, COMPARED WITH THE 13 PERCENT SUPPLIED LAST YEAR. PROJECTED U. S. NUCLEAR GENERATION IN 2000 IS A BIG PROGRAM IN COMPARISON TO ANY OTHER COUNTRY IN THE WORLD.

BUT IT IS NOT GOING TO GET ANY BIGGER.

THE EDISON ELECTRIC INSTITUTE, THE PRINCIPAL ADVOCATE FOR INVESTOR-OWNED ELECTRIC UTILITIES IN THE U. S., RECENTLY STATED:

> "..UNDER PRESENT REGULATORY AND INSTITUTIONAL ARRANGEMENTS, NO AMERICAN ELECTRIC UTILITY WOULD CONSIDER ORDERING A NEW NUCLEAR POWER PLANT."

THERE MAY NOT BE ANY NEW ORDERS FOR NUCLEAR POWER PLANTS IN THE UNITED STATES FOR THE REST OF THIS CENTURY.

THIS SITUATION IS UNPRECEDENTED. THE U.S. NUCLEAR INDUSTRY BEGAN THE DECADE OF THE 1970'S IN A SPIRIT OF UNPARALLELED OPTIMISM. ORDERS FOR NEW PLANTS ROSE FROM 27 IN 1965 TO 109 IN 1970 TO 223 IN 1974.

THROUGHOUT THE 1960'S THE JOB OF MANAGING AN ELECTRIC UTILITY IN THE U.S. WAS NOT A DIFFICULT JOB AT ALL. THE DEMAND FOR ELECTRICITY GREW AT A RAPID AND PREDICTABLE RATE: 7 TO 8 PERCENT PER YEAR. ELECTRIC CAPACITY TO MEET THAT DEMAND COULD BE ADDED AT PREDICTABLE COST:

- PREDICTABLE COST OF CAPITAL,

- PREDICTABLE COST OF CONSTRUCTION,

- PREDICTABLE TIME TO CONSTRUCT AND LICENSE,

- PREDICTABLE COST OF FUEL, AND

- PREDICTABLE REGULATORY TREATMENT OF THE OUTPUT.

AND IT WAS PROFITABLE TO CONSTRUCT NEW CAPACITY. EACH NEW PLANT WAS MORE EFFICIENT THAN THE PLANTS ALREADY IN EXISTENCE. ADDING CAPACITY LOWERED THE COST OF ELECTRICITY PRODUCED. THE MAIN JOB OF REGULATION WAS TO STEP IN FROM TIME TO TIME AND LOWER RATES SO THAT THE BENEFITS OF NEW, MORE EFFICIENT GENERATING TECHNOLOGY COULD BE TRANSFERRED FROM THE UTILITY TO THE CONSUMER.

NUCLEAR PLANTS THAT ENTERED SERVICE IN THE LATE 1960'S AND EARLY 1970'S PRODUCED AND CONTINUE TO PRODUCE ELECTRICITY AT AN AFFORDABLE 1 TO 3 CENTS PER KILOWATT HOUR. AND ELECTRIC UTILITIES ORDERED NUCLEAR PLANTS ENTHUSIASTICALLY.

AFTER 1974 ALL THAT CHANGED -- DRAMATICALLY AND FOR THE WORSE.

NUCLEAR PLANTS BROUGHT ON LINE IN THE MID-TO-LATE 1970'S BECAME PROGRESSIVELY MORE EXPENSIVE. AND THE POST-THREE MILE ISLAND PLANTS NOW THREATEN TO BANKRUPT THE UTILITIES THAT ARE BUILDING THEM.

THERE IS A MAJOR UTILITY IN MY STATE OF LOUISIANA THAT HAS 288 PERCENT OF ITS COMMON EQUITY INVESTED IN NUCLEAR CONSTRUCTION. THERE IS A MAJOR UTILITY IN MY STATE WHOSE INCOME IN 1984 WAS 106 PERCENT "ALLOWANCE FOR FUNDS USED IN CONSTRUCTION"(AFUDC). THIS UTILITY IS OPERATING ON BORROWED MONEY.

OVER A DOZEN NUCLEAR POWER PLANTS NOW ON ORDER IN THE UNITED STATES ARE ESTIMATED TO COST MORE THAN $3,000 PER KILOWATT

OF INSTALLED CAPACITY. THIS IS TEN TIMES THE GENERALLY EXPECTED CAPACITY COST OF 1970.

IN NEW YORK STATE, A NUCLEAR POWER PLANT (NIAGARA MOHAWK'S NINE-MILE POINT PLANT), WHEN COMPLETE TWO YEARS FROM NOW, WILL COST OVER $5 BILLION DOLLARS. ELECTRICITY FROM THIS PLANT MUST BE SOLD FOR 18 CENTS PER KILOWATT HOUR TO COVER THESE COSTS. THAT IS MORE THAN FIVE TIMES THE COST OF ELECTRICITY FROM EXISTING COAL OR NUCLEAR PLANTS. AN OIL-FIRED POWER PLANT WOULD PRODUCE ELECTRICITY AT 18 CENTS PER KILOWATT HOUR ONLY IF THE OIL IT USED COST $90 PER BARREL.

UTILITIES WITH ABOUT-TO-BE-COMPLETED NUCLEAR POWER PLANTS FACE UNPRECEDENTED RATE INCREASES -- 80 PERCENT TO 100 PERCENT IN SOME CASES -- TO PAY FOR THESE PLANTS. THE POLITICAL OPPOSITION TO THESE RATE INCREASES IS VERY, VERY STRONG.

THERE IS ALSO AN IDEALOGICAL OPPOSITION TO NUCLEAR POWER. BUT IT IS THE RATE INCREASES THAT DO THE REAL DAMAGE TO THE BASE OF POLITICAL SUPPORT FOR NUCLEAR ENERGY. WHEREVER THESE NEW, ULTRA-EXPENSIVE NUCLEAR PLANTS ARE ABOUT TO BE TURNED ON IN THE UNITED STATES THERE IS POLITICAL TURMOIL. IT IS DANGEROUS POLITICALLY TO BE A FRIEND OF NUCLEAR POWER. BELIEVE ME. I KNOW.

SO THERE IS, AND HAS BEEN FOR SOME TIME, A DE-FACTO MORATORIUM ON ORDERS FOR NUCLEAR POWER PLANTS IN THE UNITED STATES.

MANY PEOPLE OUTSIDE THE UNITED STATES ASSUME THAT THE U.S. CAN AFFORD TO DO WITHOUT NUCLEAR ENERGY BECAUSE OF OUR SUPPLIES OF COAL. DON'T BELIEVE IT. THE PROBLEMS OF THE NUCLEAR INDUSTRY ARE SEVERE, BUT SO ARE THE PROBLEMS OF COAL.

THERE IS A GROWING POLITICAL OPPOSITION TO COAL USE IN THE UNITED STATES. THE CONCERN OVER ACID RAIN IS A FIRST-CLASS POLITICAL ISSUE. WE HAVE NOT YET SEEN THE FULL SCOPE OF THE CONSTRAINTS THAT COAL-FIRED POWER PLANTS WILL HAVE TO MEET.

ELECTRICITY FROM NEW COAL-FIRED POWER PLANTS NOW COSTS TWO TO THREE TIMES THE COST OF ELECTRICITY FROM EXISTING COAL AND NUCLEAR PLANTS. IT TAKES 12 YEARS TO CONSTRUCT AND LICENSE A NUCLEAR PLANT IN THE U.S. IT TAKES 8 YEARS TO CONSTRUCT AND LICENSE A BIG COAL PLANT. BOTH COAL AND NUCLEAR PLANTS REQUIRE EXTENSIVE ENVIRONMENTAL REVIEW EARLY IN THE PROCESS BEFORE CONSTRUCTION CAN START.

IN THE UNITED STATES, THERE HAVE BEEN ONLY TWO NEW ORDERS FOR LARGE CENTRAL STATION COAL PLANTS IN THE LAST THREE YEARS. IN 1982 AND 1983, 29 COAL PLANTS WERE CANCELLED. DURING THE SAME PERIOD, 13 NUCLEAR PLANTS WERE CANCELLED.

SLIGHTLY OVER 50 THOUSAND MEGAWATTS OF NUCLEAR CAPACITY REMAIN ON ORDER IN THE U.S. TODAY. COAL CAPACITY ON ORDER IS ONLY SLIGHTLY OVER 30 THOUSAND MEGAWATTS.

THE U.S. IS NOT SHIFTING AWAY FROM NUCLEAR TO COAL. THE U.S. IS SHIFTING AWAY FROM THE CONSTRUCTION OF ANY NEW GENERATING CAPACITY AT ALL.

U.S. UTILITIES ARE ABANDONING BOTH NUCLEAR AND COAL AS SOURCES OF NEW ELECTRIC GENERATING CAPACITY. NOTHING IS TAKING THE PLACE OF THIS ABANDONED CAPACITY. WE IN THE UNITED STATES ARE SIMPLY IN THE PROCESS OF STOPPING THE BUILDING OF NEW ELECTRIC POWER PLANTS.

WHY IS THIS?

IT IS VERY LIKELY THAT THE U.S. WILL NEED NEW ELECTRIC GENERATION CAPACITY. GROWTH WILL REQUIRE NEW POWER PLANTS, SO EXPECTATION OF LOW GROWTH IS NOT WHY WE ARE STOPPING.

WE ARE STOPPING FOR A COMBINATION OF REASONS, ALL OF WHICH ADD UP TO AN EXTRAORDINARILY POWERFUL SET OF DISINCENTIVES TO NEW POWER PLANT CONSTRUCTION.

THERE IS UNCERTAINTY ABOUT WHAT THE DEMAND FOR ELECTRICITY WILL BE. FOR YEARS BEFORE THE 1970'S THE DEMAND FOR ELECTRICITY IN THE U.S. GREW STEADILY AT ALMOST 8 PERCENT PER YEAR. THE AVERAGE RATE OF GROWTH IN THE DEMAND FOR ELECTRICITY FROM 1977 THROUGH 1983 WAS LESS THAN 2 PERCENT. BETWEEN 1978 AND 1981, DEMAND SCARCELY GREW AT ALL. HOWEVER, LAST YEAR, IN 1984, DEMAND GROWTH JUMPED TO 4.5 PERCENT. THERE IS A BIG ARGUMENT AMONG THE EXPERTS ABOUT WHETHER FUTURE U.S. DEMAND WILL GROW AT 2, 3, 4, OR 5 PERCENT OR MORE, OR LESS. THERE SEEMS TO BE NO CONSENSUS AT

ALL.

THERE IS UNCERTAINTY ABOUT THE COST OF MONEY. IN 1965 THE PRIME INTEREST RATE IN THE U.S. WAS 4.5 PERCENT. IN 1981 IT WAS 18.9 PERCENT. THE U.S. GOVERNMENT IS RUNNING AND, IT APPEARS, WILL CONTINUE TO RUN, HUGE DEFICITS. THESE DEFICITS HAVE TO AFFECT INTEREST RATES IN THE FUTURE. BUT NO ONE KNOWS HOW OR WHEN.

THERE IS UNCERTAINTY ABOUT THE INFLATION OF THE COSTS OF CONSTRUCTION. IN 1965 THE INFLATION RATE IN THE U.S. WAS 1.7 PERCENT. IN 1980 IT WAS 13.5 PERCENT. THE U.S. INFLATION RATE IS LOW NOW, BUT NO ONE KNOWS HOW LONG THAT WILL CONTINUE.

MOST OF ALL, THERE IS TREMENDOUS UNCERTAINTY ABOUT REGULATION. WHAT BEGAN AS A FAIRLY STRAIGHTFORWARD EXERCISE OF MONITORING A GROWING INDUSTRY HAS BEEN TURNED -- BY INTERVENORS, BY THE ACCIDENT AT THE THREE-MILE ISLAND PLANT, BY THE ADVERSARY SYSTEM OF LICENSING ITSELF -- INTO A NIGHTMARE OF PAPER PUSHING THAT MOST NOW AGREE HAS VERY LITTLE SCIENTIFIC BASIS, BUT IS A LAWYER'S DELIGHT.

IMAGINE THAT YOU ARE THE PRESIDENT OF ONE OF THE PRIVATE UTILITIES IN THE UNITED STATES. IMAGINE THAT YOU ARE DECIDING WHETHER TO BUILD A NUCLEAR POWER PLANT IN THE FACE OF THESE UNCERTAINTIES.

IF YOU DO NOT BUILD THIS PLANT, BUT YOU LATER FIND OUT THAT YOU NEEDED TO, YOU WILL NOT HAVE ENOUGH CAPACITY TO SERVE YOUR CUSTOMERS. YOUR REGION WILL SUFFER, PERHAPS YOUR COUNTRY WILL SUFFER. YOU WILL BE CRITICIZED, EVEN CURSED. BUT YOU WILL BE ABLE TO SELL ALL THE ELECTRICITY YOU CAN PRODUCE. YOUR COMPANY WILL MAKE MONEY.

ON THE OTHER HAND, IF YOU DO DECIDE TO BUILD THIS PLANT, AND LATER YOU FIND OUT THAT YOU DON'T NEED IT, THERE WILL BE EXCESS GENERATING CAPACITY. THE REGULATORY SYSTEM, THEREFORE, MAY WELL NOT LET YOU CHARGE FOR THE FULL COST OF THE UNNEEDED PLANT IN YOUR RATES. YOUR COMPANY MAY GO BANKRUPT.

OR PERHAPS THE COSTS OF THE PLANT WILL GET OUT OF CONTROL OR ITS LICENSING WILL BECOME SNAGGED FOR YEARS WHILE THE INTEREST MOUNTS ON THE MONEY YOU BORROWED TO BUILD THE PLANT. YOUR COMPANY MAY BE FINANCIALLY CRIPPLED.

YOU MAY LOSE YOUR JOB.

I'M SURE THAT EACH OF YOU, IN YOUR OWN WAY, HAS GONE OVER THIS LOGIC. THEREFORE, YOU UNDERSTAND WHY, OVER THE YEARS TO COME, U.S. UTILITY EXECUTIVES AND THEIR PLANNING DEPARTMENTS ARE GOING TO ERR SERIOUSLY IN THE DIRECTION OF NOT BUILDING NEW POWER

PLANTS.

YET, THERE IS NO UNCERTAINTY ABOUT THE SAFETY AND ENVIRONMENTAL RECORD OF NUCLEAR POWER PLANTS. THIS RECORD IS EXCELLENT.

NOTWITHSTANDING THIS EXCELLENT RECORD, THE NUCLEAR INDUSTRY HAS NO NEW ORDERS AND NONE IN PROSPECT.

NOTWITHSTANDING THIS EXCELLENT RECORD, THE UTILITY INDUSTRY HAS DECIDED TO RISK CAPACITY SHORTAGES TEN YEARS FROM NOW TO AVOID THE DIFFICULTIES NEW CONSTRUCTION WOULD BRING. AN INDUSTRY THAT SHOULD PLAN FOR ITS GROWTH NEEDS IN THE LONG RUN HAS BEEN REDUCED TO PLANNING FOR SURVIVAL IN THE VERY SHORT RUN.

THE SOURCE OF MUCH OF OUR PROBLEM IS THE ACCIDENT AT THREE-MILE ISLAND. THERE, A STUCK VALVE AND OPERATOR ERROR DID MORE

DAMAGE TO THE NUCLEAR INDUSTRY IN ONE DAY THAN ALL THE EFFORTS OF ANTI-NUCLEAR INTERVENORS AND ALL THE WASTE AND CARELESSNESS OF POWER PLANT CONSTRUCTION MANAGERS COULD DO IN A DECADE. THIS ACCIDENT AND THE DRAMATIC TELEVISION COVERAGE OF THE EFFORTS TO COPE WITH IT PRODUCED AN INESCAPABLE IMPRESSION IN THE PUBLIC OF AN INDUSTRY AND A REGULATORY PROCESS OUT OF CONTROL.

EVEN TODAY, SEVEN YEARS LATER, WE HAVE NEITHER CLEANED UP THE DAMAGED REACTOR AT THREE-MILE ISLAND, NOR RESTARTED THE UNDAMAGED ONE. IN OUR INACTION, WE REINFORCE THE DOUBTS OF THE PUBLIC. OUR CONTINUED FAILURE TO DEAL EFFECTIVELY WITH THE SITUATION AT TMI, FRANKLY, REVEALS EITHER A SYSTEM AND A SET OF PROCEDURES THAT LACK THE CAPACITY TO ACCOMPLISH THE ENDS FOR WHICH IT WAS OSTENSIBLY CREATED; OR IT INDICATES THAT THE DECISIONMAKERS THEMSELVES ARE AFRAID TO MAKE A RATIONAL DECISION ON THE FACTS AND CHOOSE, RATHER, DELAY AS AN ALTERNATIVE.

THE U.S. NUCLEAR REGULATORY COMMISSION HAS BEEN TRAUMATIZED BY THE PUBLIC RELATIONS DEBACLE AT THREE-MILE ISLAND. IN THE AFTERMATH OF TMI, THE NRC PRODUCED A TORRENT OF NEW REGULATIONS AIMED AT INSURING SAFETY FROM EVEN THE MOST REMOTE CONTINGENCIES. THESE NEW REGULATIONS WERE IMPOSED RETROACTIVELY ON ALL PLANTS UNDER CONSTRUCTION. MAJOR DESIGN CHANGES HAD TO BE IMPLEMENTED EVEN THOUGH THIS MEANT TEARING OUT LARGE PORTIONS OF A PREVIOUSLY COMPLETED PLANT.

MOREOVER, THIS PROCESS IS STILL GOING ON, MAKING PLANNING FOR CONSTRUCTION OF A PARTIALLY COMPLETED PLANT ALMOST IMPOSSIBLE. TODAY, I AM TOLD, PENDING BEFORE THE NRC ARE 90 RULEMAKING AND 60 SAFETY ISSUES WITH THE TOTAL ESTIMATED POTENTIAL COST TO EACH EXISTING U.S. NUCLEAR PLANT OF $100 TO $200 MILLION IN PLANT MODIFICATION.

IN A RECENT REPORT ON BACKFITTING, THE CHAIRMAN OF THE NRC REGULATORY REFORM TASK FORCE SAID:

> "THERE IS A SUBSTANTIAL AMOUNT OF EVIDENCE THAT THE (NRC) STAFF'S BACKFITTING PRACTICES WHICH HAVE COST CONSUMERS BILIONS OF DOLLARS HAVE MADE NUCLEAR PLANTS MORE DIFFICULT TO OPERATE AND MAINTAIN, HAVE INJECTED UNCERTAINTY AND PARALYZING DELAY INTO THE ADMINISTRATIVE PROCESS AND IN SOME INSTANCES MAY HAVE REDUCED RATHER THAN ENHANCED PUBLIC HEALTH AND SAFETY."

THIS DISRUPTION IN THE REGULATORY PROCESS HAS HAD ITS EFFECTS ON UTILITY MANAGEMENT. THOUSANDS OF PROPERLY EXECUTED WELDS HAD TO BE REDONE BECAUSE DOCUMENTATION THAT THE WELDS WERE PROPER WAS MISSING. AS CONSTRUCTION TIMES LENGTHENED, CONSTRUCTION WORKERS LEARNED THAT HOURS ON THE JOB AT HIGH PAY COULD BE INCREASED IF THE NRC INSPECTOR SUSPECTED CONSTRUCTION ERRORS. HUNDREDS OF

ANONYMOUS COMPLAINTS ABOUT ALLEGED CONSTRUCTION SHORTCUTS LED TO MORE TEARING OUT AND REBUILDING. IN AN EFFORT TO GET CONTROL OF NUCLEAR CONSTRUCTION PROJECTS, NEW, OVERLAPPING LAYERS OF MANAGEMENT WERE IMPOSED. LINES OF AUTHORITY AND RESPONSIBILITY BECAME CONFUSED. AT MANY PROJECTS MANAGEMENT APPARENTLY BECAME ALMOST TOTALLY INEFFECTIVE.

AFTER THREE-MILE ISLAND THERE WAS GREAT PRESSURE TO ACCEPT ALL SORTS OF NEW SAFETY REQUIREMENTS. THERE WAS VERY LITTLE SYMPATHY FOR ANYONE SEEKING TO QUESTION THE COSTS OF THESE SAFETY REQUIREMENTS. THE NRC SIMPLY DID NOT PLACE A PRIORITY ON LIMITING COSTS. IT STILL DOESN'T.

INSTEAD, THE NRC HAS BENT OVER BACKWARDS TO BE SURE THAT IT "REGULATES", BUT DOES NOT "ENCOURAGE" THE USE OF NUCLEAR ENERGY. INSTEAD, THE NRC, WHEN FACED WITH A CHOICE BETWEEN DECISION AND DELAY, ALL TOO OFTEN CHOOSES DELAY.

WHAT NEEDS TO BE DONE?

IN THE UNITED STATES WE NEED TO ASK OURSELVES A VERY FUNDAMENTAL QUESTION. DO WE WANT NUCLEAR POWER OR NOT?

THIS QUESTION HASN'T BEEN ASKED. I THINK IT SHOULD BE ANSWERED IN FAVOR OF NUCLEAR POWER. BUT IT SHOULD BE ANSWERED SOON. ACID RAIN MAY MEAN THAT COAL IS NOT A REAL ALTERNATIVE TO NUCLEAR POWER. ULTIMATELY WE WILL HAVE TO COME BACK TO A CONSIDERATION OF NUCLEAR ENERGY FOR OUR ELECTRICITY. COGENERATION AND CONSERVATION ARE INADEQUATE SUBSTITUTES. THE EXOTIC SOURCES -- FUSION AND SOLAR ENERGY -- CANNOT POSSIBLY FILL THE GAP.

IF WE WANT THE OPTION TO TURN TO NUCLEAR ENERGY, THE U.S. NEEDS TO MAKE FUNDAMENTAL CHANGES IN ITS REGULATORY SYSTEM. IN MAKING THESE CHANGES WE SHOULD ALSO LOOK AT THE SYSTEMS THAT ARE

NOW IN PLACE IN FRANCE AND IN JAPAN. THERE, NUCLEAR POWER PLANTS ARE BUILT AND LICENSED IN HALF THE TIME IT TAKES IN THE UNITED STATES. NUCLEAR ELECTRICITY IS PRODUCED ECONOMICALLY. IS THIS BECAUSE FRANCE AND JAPAN TAKE SHORTCUTS IN SAFETY? HOW IS THE SAFETY OF U.S. PLANTS IMPROVED BY THE EXTRA 6 YEARS WE TAKE IN CONSTRUCTION AND LICENSING?

WE SIMPLY MUST FIND A WAY TO ARRIVE AT DETERMINATIONS ABOUT WHAT CONSTITUTES GOOD SCIENCE, GOOD ENGINEERING AND ACHIEVABLE SAFETY WITHOUT ALL THESE LAWYERS.

THE U.S. IS A LITIGIOUS SOCIETY. THAT WILL NOT CHANGE. I'M TOLD THAT U. S. LAW SCHOOLS LAST YEAR GRADUATED MORE LAWYERS THAN EXIST IN ALL OF JAPAN. IT IS ALSO PROBABLY POLITICALLY IMPOSSIBLE TO TOTALLY SCRAP AND THEN REBUILD THE U.S. REGULATORY PROCESS. BUT WE HAVE TO BEGIN.

ANY LONG JOURNEY BEGINS WITH THE FIRST FEW STEPS. HERE ARE SOME WE ARE CONSIDERING:

WE NEED TO DEVELOP STANDARDIZED PLANT DESIGNS AND THEN EXPEDITIOUSLY LICENSE ANY PLANT THAT IS BUILT IN ACCORDANCE WITH THOSE DESIGNS.

IT SHOULD BE POSSIBLE TO OBTAIN PRE-APPROVAL OF POWER PLANT SITES FOR THESE STANDARDIZED DESIGNS. ISSUES THAT ARE SETTLED DURING CONSIDERATION OF THESE GENERIC DESIGNS AND PRE-APPROVED SITES WOULD THEN NOT BE REVISITED IN SUBSEQUENT PROCEEDINGS IN THE LICENSING PROCESS. ONCE A STANDARIZED DESIGN IS DECLARED ACCEPTABLE, THE ONLY ISSUE IN SITE-SPECIFIC LICENSING SHOULD BE WHETHER OR NOT THE UTILITY BUILDING THE PLANT FOLLOWED THE DESIGN. WE SHOULDN'T HAVE TO DECIDE AND RE-DECIDE THE ISSUE OF WHETHER AN APPROVED DESIGN IS SAFE.

BACKFITTING OF EXISTING CONSTRUCTION SHOULD ONLY BE ORDERED WHEN IT CAN CLEARLY BE SHOWN THAT SUBSTANTIAL INCREASED PROTECTION TO THE PUBLIC HEALTH AND SAFETY WOULD RESULT AND THAT IT IS JUSTIFIED BY THE COST. A RULE OF THIS SORT IS NOW UNDER CONSIDERATION. THE NRC NEEDS TO SUMMON THE COURAGE TO MAKE FUNDAMENTAL REFORMS IN ITS EXISTING BACKFITTING PRACTICES.

AS YOU KNOW, CURRENTLY TWO NRC TRIAL-LIKE LICENSING PROCEEDINGS ARE REQUIRED BEFORE A PLANT CAN OPERATE. IT IS NOT AT ALL CLEAR THAT THERE IS ANY SIGNIFICANT ADVANTAGE TO THE PUBLIC BY HAVING TWO PROCEEDINGS RATHER THAN ONE. IF UTILITIES WILL PROVIDE ADEQUATE DESIGN INFORMATION UP FRONT, THERE NEED ONLY BE ONE SUCH PROCEEDING AND ONE LICENSE.

FINALLY, THE PROCEDURES OF THE NRC ITSELF NEED TO BE REFORMED SO THAT THE COMMISSION CHAIRMAN HAS MORE CONTROL OVER THE STAFF AND ORGANIZATION OF THE NRC. THESE PROCEDURES SHOULD ALSO BE

REFORMED TO MAKE SAFETY AND GOOD SCIENCE AND ENGINEERING GOALS OF THE PROCESS, RATHER THAN BENEFITS THAT WE CAN ONLY HOPE WILL EMERGE FROM AN ADVERSARIAL PROCEEDING.

NOT ALL OF THE CHANGES HAVE TO BE MADE AT THE NRC.

WE NEED TO GET THE ATTENTION OF THAT PART OF THE PUBLIC THAT INFLUENCES OPINION. THIS MEANS CREDIBLE, FORCEFUL ANALYSES OF THE PROBLEM. THE EDISON ELECTRIC INSTITUTE HAS RECOMMENDED THAT AN EXPERT NATIONAL COMMISSION ON ELECTRICITY BE APPOINTED TO REPORT TO CONGRESS WITHIN SIX MONTHS ON FUTURE GROWTH IN DEMAND AND HOW NEEDS CAN BE MET BY DEMAND REDUCTIONS AND INCREASES IN SUPPLY. GIVEN THE RIGHT MEMBERSHIP AND A TIMELY REPORT, SUCH A COMMISSION COULD PROVIDE A POWERFUL FOCUS FOR ACTION. IF WE ARE GOING TO HAVE A NATIONAL COMMISSION ON ELECTRICITY WE SHOULD GET ON WITH IT.

TOGETHER WE MUST STUDY AND UNDERSTAND THE REASONS WHY THE MOST EXPENSIVE PLANTS BECAME SO EXPENSIVE AND WHY THE PLANTS THAT CAME IN ON TIME AND UNDER BUDGET DID SO. THERE HAVE TO BE LESSONS FOR US IN BOTH OUR MANAGEMENT SUCCESSES AND OUR MANAGEMENT FAILURES. WE NEED TO KNOW WHAT THOSE LESSONS ARE.

WE NEED TO UNDERSTAND WHY, IN JAPAN, FOR EXAMPLE, THE CAPACITY FACTOR OF NUCLEAR PLANTS IS SO HIGH - 95 PERCENT IF SHUTDOWNS FOR REGULAR INSPECTIONS ARE DEDUCTED. WE NEED TO UNDERSTAND WHY REACTOR "SCRAMS" PER HOUR OF OPERATION ARE SO MUCH LOWER IN JAPAN THAN IN THE UNITED STATES.

THE INDUSTRY MUST JOIN WITH THE FEDERAL GOVERNMENT TO MAKE SURE THAT WHEN THE NATION TURNS AGAIN TO NUCLEAR ENERGY, AS WE BELIEVE IT MUST, BOTH THE RIGHT MANAGEMENT STRUCTURE AND THE RIGHT PRODUCT ARE AVAILABLE. THIS MEANS AN AGGRESSIVE PROGRAM TO LOOK AT ALTERNATE REACTOR CONCEPTS, FOR EXAMPLE; AT PASSIVE

SAFETY SYSTEMS; AT SMALLER, MODULAR PLANTS; AT THE BEST IDEAS OUR CREATIVE PEOPLE CAN COME UP WITH. WE NEED TO TREAT NEW IDEAS AS OPPORTUNITIES, NOT THREATS.

AND, IN THE PRESENT BUDGETARY CLIMATE, THIS PROGRAM MUST INVOLVE SUBSTANTIAL COST-SHARING BETWEEN GOVERNMENT AND INDUSTRY.

WE MUST ALSO DEVELOP THE TECHNOLOGY THAT CAN KEEP COAL BURNING AS A VIABLE ELECTRICITY TECHNOLOGY. THE CLEAN COAL TECHNOLOGY PROGRAM NOW GATHERING SUPPORT IN CONGRESS AND IN INDUSTRY DESERVES YOUR SUPPORT TOO. THE ALLIANCE BETWEEN COAL AND NUCLEAR POWER ADVOCATES IS NOT ONLY RIGHT, IT IS ESSENTIAL. IT IS GOING TO TAKE THE FULL EFFORTS OF ALL OF US TO TURN THE CURRENT SITUATION AROUND. AND OUR GOAL IS THE SAME: ADEQUATE SUPPLIES OF ELECTRICITY AT REASONABLE AND PREDICTABLE PRICES.

FINALLY, WE NEED A COORDINATED AND COMPREHENSIVE PLAN OF ACTION FOR ELECTRIC POWER AND FOR NUCLEAR POWER. THIS PLAN SHOULD SET FORTH THE ROLE THAT WILL BE PLAYED BY GOVERNMENT AS WELL AS THE RESPONSIBILITIES OF INDUSTRY. IT SHOULD ASSESS THE COSTS AND SPECIFY THE RESOURCES THAT WILL COVER THOSE COSTS. IT SHOULD IDENTIFY THE TECHNOLOGIES AND THE INSTITUTIONAL STRUCTURES WE ARE SEEKING. IT SHOULD PUT SOMEONE IN CHARGE.

MANY OF THESE PROPOSALS SEEM SO EMINENTLY REASONABLE AND SENSIBLE THAT IT IS A WONDER THAT THEY WERE NOT IMPLEMENTED LONG AGO. OF COURSE, THERE ARE ARE LOTS OF REASONS.

CERTAINLY, ONE REASON IS THAT THE U.S. REGULATORY SCHEME HAS NOT RECOVERED FROM THE NIGHTMARES OF THE 1970'S.

CERTAINLY ANOTHER IS THAT THE CURRENT ADMINISTRATION, FOR ALL ITS GOOD WORDS, IS TOTALLY UNACCUSTOMED TO ACTIVIST LEADERSHIP

THAT CAN INTERVENE WHEN THINGS ARE GOING WRONG AND PUT THEM RIGHT. INDEED, ACTIVIST LEADERSHIP MAY NOT EVEN BE COMPATIBLE WITH THE FREE MARKET IDEOLOGY THAT PERVADES SO MUCH OF THE ADMINISTRATION'S ATTITUDE TOWARDS PROBLEMS. BUT IT IS CLEAR TO ME THAT THE ELECTRIC SECTOR IN GENERAL AND NUCLEAR POWER IN PARTICULAR DESPERATELY NEED ACTIVIST LEADERSHIP AND NEED IT NOW.

AND MOST CERTAINLY, THESE FAILURES CAN BE TRACED TO THE POOR APPRECIATION BY THE PUBLIC IN THE U.S. OF THE IMPORTANCE OF NUCLEAR ENERGY TO THE NATION'S CURRENT ELECTRICITY SUPPLY. THERE IS EVEN LESS APPRECIATION OF THE MUCH LARGER POTENTIAL IMPORTANCE OF NUCLEAR ENERGY IN THE FUTURE. THOSE OF US WHO DO SEE THE IMPORTANCE OF NUCLEAR ENERGY TO OUR FUTURE MUST FIND EFFECTIVE WAYS TO GET OUR MESSAGE TO THE PUBLIC.

THE NEED FOR ENERGY IN AN INDUSTRIALIZED SOCIETY IS AN IRRESISTIBLE FORCE. IN THE UNITED STATES, TOO MUCH MISGUIDED

REGULATION AND TOO LITTLE EFFECTIVE LEADERSHIP HAVE SET UP IMMOVABLE OBJECTS THAT PREVENT THE ECONOMICAL SUPPLY OF THAT ENERGY FROM NUCLEAR POWER.

HERE WE HAVE THE CLASSIC STANDOFF BETWEEN PROGRESS AND STAGNATION. IN THE RESOLUTION OF THIS STANDOFF, I HOPE, I BELIEVE, THAT THE UNITED STATES WILL REJECT THE STAGNATION THAT LOOMS BEFORE US AND CHOOSE PROGRESS WE CAN BEGIN TO SEE CLEARLY, BUT HAVE YET TO GRASP.

The **CHAIRMAN**. I will turn the podium over to Senator Metzenbaum.

STATEMENT OF HON. HOWARD M. METZENBAUM, A U.S. SENATOR FROM THE STATE OF OHIO

Senator **METZENBAUM**. Mr. Chairman I am particularly interested in the subject, and am concerned about it. As I sat here, I began to think about one of the reasons we probably do have some shortages or will have some. And that is, because generation capacity, electric power from nuclear energy, and new plant construction, has pretty much come to a standstill.

We oftentimes find ourselves in the political world discussing too much Government regulation, not enough Government regulation, and sometimes Government regulation or lack of regulation goes askew.

I think if there was ever an area where that is most clearly evident, it was when we turned over to the Atomic Energy Commission the authority to push for the development of new nuclear facilities and aid in their development, and at the same time gave them responsibility to see to it that the public would be protected from the development of those nuclear facilities.

As a consequence, the AEC gave all of the emphasis to the first part of the equation having to do with the development of new facilities and gave very little concern to safety and security. As a consequence, the industry did not live up to the standards that might have been more appropriate had there been stronger Government regulation or at least standards that they themselves had set.

As a consequence, we found a number of accidents—near-misses, fortunately—develop. We found the American people very frightened by the development of nuclear power facilities near their homes or their businesses, and the net result is that the Government's pendulum swings the other way, and we get tougher and tougher and tougher.

The bottom line is that to the best of my knowledge, there are very few new nuclear facilities that are on the drawing boards at the present time. I think that is probably sad. Other nations in this world are using nuclear power. Apparently we use less, rather than more, and we probably will be facing the question of how we get that additional power. And it is not an easy answer. Whether it is gas, or coal, or some other source. They all have some pluses and minuses. I commend you for holding these hearings in order that the entire subject may be explored.

Although I will not remain for the entire hearing, it is not from a lack of interest, but it is from a commitment to be at another hearing.

The **CHAIRMAN**. Thank you, Senator.

Senator Evans.

STATEMENT OF HON. DANIEL J. EVANS, A U.S. SENATOR FROM THE STATE OF WASHINGTON

Senator **EVANS**. Thank you, Mr. Chairman.

As you might guess, this set of hearings is a very interesting one for me, having had the opportunity for 3 years prior to coming to the Senate to serve as chairman of the Pacific Northwest Regional Power Planning Council, and having engaged in much of the same activity we will hear about during these 2 days, which I think will be of extreme interest not only to the committee, but ought to be of extreme interest to the Nation.

We are in a time of energy complacency. Everything seems to work out just fine. The price of oil is down. The lights go on. There are no disruptions either in price or in supply currently that cause people to unduly worry.

That complacency is most recently reflected in the decision of the Department of Transportation to reduce automobile fuel efficiency standards. It is reflected in the disarray among OPEC nations, and the resulting expectation of oil price reductions which leads to further complacency.

But of all of the energy sources, perhaps electrical energy is subject to the greatest uncertainty. We have a long, long list of canceled central station plants. We have been subjected over the past two decades to, first, simplistic forecasting—and frankly, I was astonished at the beginning of our efforts in the Pacific Northwest to find out how simplistic that electric forecasting was at the time.

And then we engaged in the decade of overforecasting, understandably, I think, because to most utility executives the worst thing that could happen was to have a shortage, to end up as a result of shortage faced with brownouts or blackouts, and in those earlier days it was not costly to carry a substantial excess in generating capacity.

We have simply got to find a way to do a better job of forecasting now. We have to recognize the enormous regional disparities which exist, and search out for ways in which regions can work more closely together to use the best of the resources of each region, and, in doing so, add to the benefits of both.

I think that there is a particular potential in the activities between the Northwest and the Southwest of the United States. That experience in the Pacific Northwest Power Planning Council led us to realize very quickly that no one was wise enough to forecast a single line prediction for any substantial period of time in the future, and we gave that up very quickly and rather figured that we could do a better job perhaps of identifying the boundaries, the extremes on the high and the low side, which does not help much if you end up with a very wide band, unless you at the same time can provide the mix of resources which can meet any projected load within that band in a reasonable timeframe.

We did, Mr. Chairman, develop the options process, which I think has great merit, and which ought to be pursued through this hearing and beyond, an options process which we hoped would cut the times between the investment of large sums of money and the coming on line of new generating plants.

It is the risk of time which seems to hold everyone back more than any other thing. I think it is also important that we throughout the country give correct price signals to our consumers, correct price signals by assuring that we are including in the cost of each generating station all of the quantifiable environmental costs, and those must include for a nuclear plant the decommissioning and the storage of wastes, for a coal plant the necessary environmental controls, sufficient environmental controls to halt the environmental damage which, at least a good deal of evidence indicates, occurs because of inadequate controls.

But finally, Mr. Chairman, I think the place where we can search with the greatest chance of reward for sufficient electrical energy for our long-term future is in the greater efficiency with which we use electric energy. I think there is a particularly large potential in industrial energy efficiencies.

I don't believe we ought to shy away from the concept of sharing in the cost or even purchasing outright those new efficiencies. We simply must look on each home, each business, each commercial establishment of this Nation as a miniature generating station. We, all of us, own a valuable resource, and we ought to be able to sell it if it is cheaper and better and can provide the necessary resource to those who need it.

A good deal of work is being done in the Pacific Northwest, and I am particularly pleased with some of the more recent suggestions made from the industrial sector which could provide very substantial amounts of electricity through new efficiencies, and for which, I think, the generators, those who need the electricity, ought to be willing to pay at least a share.

Mr. Chairman, these hearings are important. The expectations for projected new capacity for the remainder of this century are huge, and the costs are enormous. We simply must put emphasis on reducing risk where we can, on attempting to get better in our ability to forecast needs for the future, in avoiding rate shocks which have such enormous impacts both on individuals and on our industrial base, and I hope that we in the process provide some help, some direction that will once again renew the faith of our utility executives in making the necessary investments in new plants.

I fear that in too many cases the idea is to avoid any major new exposure, any major new investment, and hope that disaster does not happen while they are still on watch. That is not a very healthy sign for our future, and I hope these hearings will give us some better ideas for how we proceed, Mr. Chairman.

The **CHAIRMAN**. Thank you, Senator Evans.

Senator Ford.

Senator **FORD**. I am here to be enlightened.

The **CHAIRMAN**. We will hear from the first panel, which is composed of Dr. Daniel Dreyfus, Dr. William Hogan, Dr. Mark French, Mr. Stephen Smith, and Dr. Kemm Farney.

We will hear first from Dr. Dan Dreyfus, who of course is no stranger to this committee, having worked on both that side of the table and this for a good many years. You are welcome back here. We always look forward to hearing from you.

STATEMENT OF DR. DANIEL A. DREYFUS, VICE PRESIDENT, STRATEGIC ANALYSIS AND ENERGY FORECASTING, GAS RESEARCH INSTITUTE

Dr. **DREYFUS**. Thank you, Mr. Chairman.

This is my first time back in 4 years, and I notice that my chewing gum is missing from under the table.

The Chairman. Well, we have a new regime here. We cleaned up the table. [Laughter.]

Dr. Dreyfus. Thank you, Mr. Chairman. I appreciate your invitation to present the statement on the outlook for the electric utility industry.

I am Dan Dreyfus, vice president for Strategic Analysis of the Gas Research Institute, GRI. GRI is a not for profit membership organization of natural gas pipelines and distribution companies that plans and manages R&D in gas technologies. GRI intends its research and development investments to address the most important technological issues confronting the natural gas industry and to provide the maximum benefits to the industry and its consumers.

In order to plan and evaluate such an R&D program, GRI prepares an annual comprehensive projection of U.S. energy supply and demand with particular emphasis on the role of natural gas and carries out a continuing program of economic studies concerning energy issues that may affect the viability of new gas technologies.

My statement this morning will draw heavily upon strategic and technology analyses that were carried out by GRI. However, some of the more judgmental conclusions that I will offer are my own, and are not necessarily any corporate view of GRI. An executive summary of GRI's 1984 baseline projection of U.S. energy supply and demand is attached to my statement.

I have provided the committee staff with a good deal of backup to that summary. The projection generally represents a future with reasonable economic growth that rates slightly below the long-term historical experience, strong energy conservation trends, and increased use of renewable energy, despite projections of relatively low rates in energy prices.

Our projection, which is reasonably consistent with many contemporary forecasts expects energy demand to increase at about half the rate of GNP. Oil demand would grow slightly more slowly than the overall energy demand, but electricity demand would grow more rapidly. In our 1984 projection, electricity demand is found to grow at the average rate of 2.4-percent annually, which is about 85 percent of the GNP growth rate. Some forecasters predict more rapid growth in electricity demand.

The most recent Department of Energy annual outlook, for example, projects a growth rate of about 3.2 percent for electricity, which is slightly above the projected GNP growth rate.

There are two approaches commonly used to forecast electrical energy demand. There is the top down approach in which some relationship is assumed between electricity demand and GNP or electricity demand and per capita use which is based upon either historical experience or intuition, or is sometimes just wishful thinking. That relationship is then used to project the requirement for future electricity.

A more complex bottoms up approach draws upon the rather extensive physical information that we have about energy-using equipment and energy-producing systems, and strives to develop trend lines in those relationships. We at GRI, use the second type of approach.

It is not necessarily more reliable, because the assumptions that have to be put into that data-hungry system are just as uncertain as the gross assumptions about the per capita use of electricity. But that methodology does require one to take a hard look at the physical systems and to recognize some of the constraints that restrict the pace at which transitions in energy systems are capable of taking place.

A significant point about demand projections is, they usually do not take into account any constraint upon the availability of electricity except the price that it costs to get it. On the supply side of the equation, nearly all forecasters begin by acknowledging that the existing generating system in the U.S. exists, and assume that the existing construction programs of the electric utilities will substantially be carried out.

As a result of a long history of regulation, there is more practical information available about the capabilities and the plans of the electric utility industry than there is about any other sector of the energy business. Recognizing the long lead times associated with new powerplant construction, the outlook for electric utility decisions about new generating capacity can be drawn directly from current utility plans, and will carry a forecaster well into the 1990's.

Beyond that time, the forecasters must presume the choices that will be made by the utilities in order to provide the new capacity that the demand requires. The GRI projection assumes based on current circumstances that a few of the nuclear plants currently remaining under construction will be further delayed, and that some currently planned coal plants also will be deferred. Otherwise, we assume that the planned new capacity will be completed.

Along with many contemporary projections, we also assume that all of the major long-term central station capacity additions that are initiated beyond the current plans of the utilities will be coal-fired. We simply conclude that the current public attitudes and utility management considerations will exclude any new nuclear orders for the rest of this century.

We also recognize that existing legal barriers prohibit the construction of new gas and oil-fired generation except in a few highly specialized situations that one cannot approach in a macroanalysis. Obviously, we are not making normative decisions that nuclear plants should not be initiated, and certainly we are not making decisions that gas plants would not be appropriate. We are simply recognizing the facts of life as they appear today.

Senator **Metzenbaum**. Dr. Dreyfus, I do not want to interrupt you, but I am going to have to leave, and I am sort of curious about one thing. Why is it so difficult to construct new gas and oil-fired generators?

Dr. **Dreyfus**. Prohibitions of the Fuel Use Act simply prohibit the construction of gas-fired or oil-fired powerplants. A gas-fired powerplant may be built under a set of exemptions, which you may recall, but the exemptions for the most part are so specialized that in an orderly planning process one cannot plan for them. They, for example, permit you to build a gas plant for system reliability once you're in deep trouble, and if the exemption is in fact approved. They also provide exemptions for certain specialized technological applications where they can be converted to coal gasifiers in the future.

That is a technology not yet completely proven, and the timing is at the discretion of the Secretary of Energy. So as a part of an orderly utility planning process, one cannot build those plants in. There will probably be a few built under exemptions, but we cannot predict that.

Senator **Metzenbaum**. Thank you.

Dr. **Dreyfus**. We are carrying out studies to improve our estimates of renewable energy and conservation and our ability to reflect an increasing role for cogeneration in offsetting the demand for central station generating capacity. Our current projection includes 0.7 quads of electric energy provided by industrial cogeneration in the year 2000.

In our 1985 update we will also include an estimate of commercial cogeneration. We have a heavy gas-fired cogeneration R&D program at GRI and we're particularly interested in the potential for that technology.

We are forecasting an increasing role for electricity in a growing national energy demand that would require about 180 million kilowatts of new central station capacity by the year 2000. About 130 million kilowatts of this capacity would be needed by the mid-1990's, which is already within the lead time required to construct a new coal-fired powerplant.

To meet this goal, nearly all of the construction currently planned by the electric utility industry would have to be accomplished substantially on schedule. It is not clear that even the utility industry itself intends to carry out that program. There are serious financial disincentives and in some cases regulatory impediments that make aggressive construction programs unattractive in the existing oversupply situation.

Some current expressions by utility managers suggest that the industry no longer intends to pursue its traditional practice of investing heavily for future reliability. If the construction program does lag, capacity shortfalls could begin to occur in some systems at times of peak demand within a few years.

A chronic and widespread reliability problem could evolve by the mid-1990's, exacerbated by the long lead time necessary to finance and construct new capacity in an efficient manner.

I will omit the portion of my statement that deals with the uncertainties of forecasting, because you have a panel of very good forecasters here who I'm sure will dwell upon those problems. And I would say that the GRI projection, I believe, presents a balanced approach to the energy future. It assumes that strong conservation and efficiency trends will continue. It anticipates only modest long-term economic growth. Nevertheless, it projects a growing demand for electricity and a requirement for a substantial amount of new capacity.

Assuming that the growth in demand for electricity does track economic expansion in the range of 50 to 100 percent of the rated GNP growth, there are further uncertainties about the ability of utility systems to meet the demand.

Existing reserve margins in some systems are quite large. Imminent new powerplant completions will increase the margins, and there are various expectations for load management programs, nonutility generation, including cogeneration, and outright efficiency improvements to reduce the need for new central station additions. It is also probable that existing powerplants will be more frequently rebuilt rather than retired.

But there are significant questions about the reserve margin. Many theorists consider existing capacity as if it were universally useful. In fact, much of it is old and inappropriate for extended service. Some of it is specialized—pumped storage and small turbines. Twenty percent of current generating capacity is oil-fired. If that capacity was used in more extensive service to meet load growth, it could add dramatically to oil imports and aggravate the current trade balance crisis.

Any emerging capacity shortfall will initially appear as a peak load or system reliability problem. The potential to mitigate peak demand growth through load management remains a major uncertainty.

Direct interruption of service is of course effective in those areas where it is practical. Indirect load management through economic incentives and disincentives is much more speculative. Typically, the critical peaks are the most difficult to influence in this way. Air-conditioning on the hottest day, heat on the coldest, hot water in the mornings and evenings, and TV in prime time have a particularly high value to most consumers.

We have done several studies of cogeneration and I have included in my statement some of our assumptions and our predictions about cogeneration capability. I would simply like to state that under the current policy cogeneration has been conceived primarily as a nonutility undertaking.

The decisionmakers who must provide the facilities therefore will not be an integral part of the regulated utility industry. There will be hundreds of free agents who will decide to participate based on their own current appraisals, not only of the economic viability of cogeneration, but also the relative attraction of cogeneration and other investments. They will be free to enter the system when the return looks good and to stay out or cancel their plans when the situation changes. Reliance upon nonutility generation, load, management programs and projected conservation for significant contributions to system reliability introduces a great deal of new uncertainty into utility planning.

Short leadtimes are associated with most cogeneration ventures, only 1 to 3 years from commitment to completion. There are very few short leadtime fallbacks available to utilities if demand should exceed expectation and nonutility generators should fail to materialize. Studies done by GRI indicate that gas-fired combined cycle powerplants could provide an economical form of short leadtime capacity if public policy were revised to enable utilities to plan for their use. This would be a particularly valuable option where unanticipated capacity shortfalls do occur.

In summary, although there is no current evidence that electric demand will return to the runaway rates of growth of the sixties and seventies, the growth over the last 2 years has indeed been significant. It seems dangerous to assume a long-term future in which reliability depends chiefly upon extraordinary advances in conservation and peak load management.

Long-term growth of electrical demand at rates between 50 and 100 percent of GNP are far more likely to occur. Such rates of growth inevitably will require a sustained program of generating capacity renewal and additions. The situation today severely discourages utilities from pursuing an orderly construction program until the new demand growth is a matter of historical evidence.

The leadtimes that seem to be unavoidably associated with conventional powerplant industry make this approach hazardous. Some of the potentially desirable options for rapid reaction to unanticipated demand growth, especially utility-sponsored cogeneration from gas-fired combined cycle powerplants, are currently constrained by public policy.

Finally, it's not clear today where the responsibility rests to plan for the future reliability of the U.S. electric power system. Utilities have been severely penalized for past errors of forecasting and overcommitment. Under current regulatory policies the risk of investing in unneeded capacity is overwhelming.

It is less clear who bears the risk of shortages. Certainly the burden of a shortage falls on the consumer in the form of industrial plant interruptions, personal inconvenience, and in extreme situations even threat to public safety. But consumers in a modern technological society cannot plan electric reliability, nor can they escape the impacts of shortfalls.

Neither are their representatives in regulatory bodies notably well equipped or organized to plan utility programs. The utilities themselves used to shoulder the responsibility to plan for reliable service. Today, as purchased power and nonutility decisions are substituted for generation, they have much less direct control over the evolution of even their own systems.

Additionally, the financial risk of doing business is heavily biased against construction. The real problem facing the electric utility system today may most easily be characterized as a crisis in planning.

Mr. Chairman, I have a prepared response to seven questions that were posed by the committee staff in a memorandum, and I would like to offer that as an addendum to my statement. And I am prepared to answer questions as you see fit.

[The prepared statement of Dr. Dreyfus follows:]

Statement of Dr. Daniel A. Dreyfus
Vice President
Strategic Analysis and Energy Forecasting
Gas Research Institute

before

The Committee on Energy and Natural Resources
United States Senate

A hearing entitled:
"When Will the Lights Go Out?"
July 23, 1985

Introduction

Mr. Chairman, I appreciate your invitation to present a statement to the Committee on the outlook for the electric utility industry in the United States.

I am Dan Dreyfus, Vice President for Strategic Analysis and Energy Forecasting of the Gas Research Institute (GRI). GRI is a not-for-profit membership organization of natural gas pipeline and distribution companies that plans, manages, and develops financing for a cooperative research and development program designed to advance the technologies for gas supply, transport, storage, and end-use and to conduct related basic research. GRI acts as an R&D investment broker by bringing together the research and business expertise of universities, manufacturers, R&D institutions, and government laboratories to focus on the needs of the regulated gas industry and its customers. Over 300 individual projects are currently being performed by leading research organizations under GRI contracts.

GRI intends its research and development investments to address the most important technological issues confronting the natural gas industry and to provide the maximum benefits to the industry and its customers. In order to plan and evaluate its R&D program, GRI prepares an annual comprehensive projection of U.S. energy supply and demand, with particular emphasis on the role of natural gas, and carries out a continuing program of economic research concerning energy issues that may affect the viability of new gas technologies.

My statement will draw heavily upon strategic and technology analyses carried out by GRI; however, some of the more judgmental conclusions I will offer are my own and are not necessarily the corporate views of GRI.

Projecting Electricity Demand

An Executive Summary of GRI's 1984 Baseline Projection of U.S. Energy Supply and Demand is attached to my statement, and the Committee staff has been provided with more detailed backup material. The projection generally represents a future with reasonable economic growth, at rates slightly below the long-term historical experience. Strong energy conservation trends and increased use of renewable energy are projected, despite relatively low rates of growth in energy prices. In our 1985 update, which is now being prepared, our projection of oil, gas, and coal prices will all be further reduced.

Our projection, which is reasonably consistent with many contemporary forecasts, expects energy demand to increase at about half the rate of GNP growth. Oil demand is expected to grow more slowly than overall energy demand, but electricity demand will grow more rapidly. In our 1984 projection, electricity demand is found to grow at the rate of 2.4 percent annually, or 85 percent of the GNP growth rate. Some forecasters predict a more rapid growth in electricity demand. The most recent Department of Energy

Annual Energy Outlook, for example, projected a rate of growth of about 3.2 percent, which is slightly greater than their projected rate of GNP growth.

Two approaches are commonly used to forecast electrical energy demand. In the "top down" approach, electricity demand is assumed to be related to some more general factor in the socio-economic outlook. Population or general economic activity are commonly used. A trend in the per-capita or household requirement for electricity or in the ratio of electrical demand to GNP growth is derived from historical experience, intuition, or, in some instances, wishful thinking. The demand for electricity is then calculated and attributed to the general demographic or economic outlook.

More complex, or "bottom up" analyses, take account of the capability of existing energy using and producing systems. Based upon projected trends in the future requirements for specific energy service needs, such as space conditioning, they simulate the economic choices that will be made as households and businesses select energy sources to serve those needs.

The GRI projection is of the second type. It is not necessarily more "reliable" given the underlying uncertainties about the future, but the methodology does force the analyst to recognize some of the specific constraints that restrict the pace of transitions in the physical energy systems.

Projecting Electrical Supply

The significant point about most demand projections, of course, is that they do not take into account any constraint upon the availability of electricity to meet the projected demand other than the cost of providing the required supply.

On the supply side of the equation, nearly all forecasters begin by acknowledging the existing generating systems in the U.S. and assuming that existing construction programs will be substantially carried out. As a result of its long history of regulation, there is more information available on the capabilities and plans of the electric utilities than on any other sector of the energy industry. Recognizing the long lead time associated with the construction of new powerplants, the outlook for utility decisions about new generating capacity that can be drawn directly from current utility plans will carry a forecast well into the mid-1990s. Beyond that date, forecasters must make judgments about the economic choices that utilities will make to provide the new capacity that the demand projection requires.

The GRI projection assumes, based on current circumstances, that a few of the nuclear plants now remaining under construction will be further delayed and that some currently planned coal plants also will be deferred. Otherwise, it assumes that planned new capacity will be completed.

Along with many contemporary projections, GRI also assumes that all of the major, longer-term central station capacity additions beyond the currently planned programs will be coal-fired. We simply conclude that current public attitudes and utility management considerations will exclude new nuclear orders for the rest of this century. We also recognize that existing legal barriers prohibit the construction of new gas and oil-fired generation, except in a few highly specialized situations that cannot be reflected in macro-analyses.

We are also carrying out special studies to improve our estimates of renewable energy and conservation and our ability to reflect an increasing role for cogeneration in mitigating the demand for central station generating capacity. Our 1984 projection includes 0.7 quadrillion Btus (quads) of electric energy provided by industrial cogeneration in the year 2000. Our 1985 update will also include an estimate of commercial cogeneration. We expect natural gas to supply an important part of this cogeneration demand, and because we are funding an aggressive R&D program in gas-fired cogeneration technologies, we are quite interested in the potential for cogeneration.

The 1984 GRI projection forecasts an increasing role for electricity in a growing national energy demand that would require about 180 million kilowatts of new central station capacity additions by the year 2000. About 130 million kilowatts of this capacity would be needed by the mid 1990s, which is already within the lead time required to construct a major new coal-fired powerplant.

To meet this goal, nearly all of the construction currently planned by the electric utility industry would have to be accomplished substantially on schedule. It is not clear that even the utility industry itself intends to carry out that program. There are serious financial disincentives and, in some cases, regulatory impediments that make aggressive construction programs unattractive in the existing oversupply situation. Some current expressions by utility managers suggest that the industry no longer intends to pursue its traditional practice of investing heavily for future reliability.

If the construction program does lag, capacity shortfalls could begin to occur in some systems at times of peak demand within a few years. A chronic and widespread reliability problem could evolve by the mid-1990s, exacerbated by the long lead time necessary to finance and construct new capacity in an efficient manner.

Uncertainties

Of course, the overriding uncertainty confronting all forecasts is the inherent potential for the future to differ from the past. In the mid-1970s, after a decade of unprecedented continuous and rapid economic growth, we were incapable of believing that the six and seven percent annual growth rates in electricity demand could be moderated more than a little by energy price shocks, government policy, and public attitudes. While private and public reactions to the energy crisis, a deep and persistent recession, and the restructuring of the U.S. industrial base held electrical demand growth nearly level between 1979 and 1983, forecasters continued to insist that high growth rates were about to resume.

We really do not yet understand the dynamics of the energy demand slump. Many concurrent trends have contributed to recent history:

- Significant increases in energy prices relative to other factors of production and other consumer goods have changed consumption patterns and have made efficiencies of energy use more economic.

- Reduced overall demand for, and increased imports of, the products of energy intensive heavy industries, such as steel, along with increased activity in the high-technology and service industries have altered the relationship of energy to GNP.

- Increased imports of energy in the form of manufactured consumer goods (such as automobiles) have reduced the domestic energy demand associated with consumer spending.

The protracted global recession, which has not yet entirely run its course in Western Europe, also overlies all of these other factors and influences recent historical statistics to an indeterminate degree.

Recent statistics have indicated a surprisingly persistent refusal of energy demand to increase with economic recovery. These statistics are cited as evidence that, despite an expectation of cheap and plentiful energy in all its forms, the attitudes of energy users will remain unchanged, and that energy demand will not have to regain substantial growth trends to support increasing economic activity.

On the other side of the argument, there is evidence that the current expectations of stable or decreasing energy prices will have an impact on decisions and that some of the recent energy efficiency and conservation trends are deceptive. With the U.S. economic recovery behind us, and in a year of unexciting economic activity, the year-over-year energy demand statistics are now occasionally showing increases. Electrical peak demands have been setting records in many systems in both summer and winter seasons. As an indication of public attitudes, the newest automobiles are again becoming less efficient, although the fleet average efficiency continues to increase.

The GRI projection reflects, I believe, a balanced approach to the energy future. It assumes that strong conservation and efficiency trends will continue, and it anticipates only modest long-term economic growth. Nevertheless, it projects a growing demand for electricity and a requirement for substantial amounts of new capacity.

Assuming that the growth in demand for electricity does track economic expansion in the range of 50 to 100 percent of the rate of GNP growth, there are further uncertainties about the ability of utility systems to meet the demand. Existing reserve margins in some systems are quite large. Imminent new powerplant completions will increase the margins, and there are various expectations for load-management programs, non-utility generation (including cogeneration) and outright efficiency improvements to reduce the need for new central station additions. It is also probable that existing powerplants will more frequently be rebuilt rather than retired, with implications for the costs and fuel choices of future capacity.

There are significant questions, however, about the reserve margins which are considered to exist today. Many optimistic theorists consider the existing capacity as if it were universally useful. In fact, some of it is highly specialized, for example pumped storage peaking plants or small peaking turbines, and is not available for general use. A portion of the reserve consists of inefficient old plants which would be undesirable for increased service. Furthermore, about 20 percent of current U.S. electrical generating capacity is oil-fired. Much of it is not used extensively, but it is included in the ostensible reserve numbers. Serving load growth with the increased operation of oil-fired capacity translates directly into increased oil consumption. Any increase in U.S. oil consumption must, in turn, be served by imports. Regardless of availability and prices, increased oil imports will aggravate the trade balance crisis.

Any emerging capacity shortfall will initially appear as a peak load, or system reliability, problem. The potential to mitigate peak demand growth through load management remains a major uncertainty. Certainly, direct measures such as interrupting service to certain users can be used to level peaks. This has been done for years in systems where suitable interruptible users exist. The extent to which the concept can be extended is difficult to measure.

Indirect load management, through economic incentives and disincentives, is much more speculative. Typically, the critical peaks are the most difficult to influence in this way. Air conditioning on the hottest day, heat on the coldest, hot water in the morning and evening. and TV in prime time have a particularly high value to most consumers.

The probable role of cogeneration and other forms of non-utility contributions to electric energy supply is also difficult to forecast.

Under current policy, cogeneration has been conceived of primarily as a non-utility undertaking. The decisionmakers who must provide the facilities will not be an integral part of the regulated utility industry. They will be hundreds of free agents who will decide to participate based upon their own current appraisals, not only of the economic viability of the individual ventures, but also the relative attractiveness of these investments compared to the potential returns on other kinds of ventures. They will be free to enter the system when the returns look good, and free to stay out or cancel their plans when the situation changes.

Recent GRI studies indicate that as much as 27,000 additional megawatts of generating capacity in industrial applications and about 15,000 megawatts in the commercial sector could economically be provided by cogeneration installations by the year 2000. Although this contribution would make economic sense and would obviously greatly reduce the requirement for central station generating facilities, it is not clear that the appropriate combinations of users, entrepreneurs and financiers will materialize to make the potential a reality.

Reliance upon non-utility generation, load management programs and projected conservation for significant contributions to system reliability introduces a great deal of uncertainty into utility planning. Short lead times are associated with most cogeneration ventures, only one to three years from commitment to completion. There are few short-lead-time fallbacks available to a utility if demand should exceed expectations and non-utility generators should fail to materialize. Studies done by GRI indicate that gas-fired, combined-cycle powerplants could provide an economical form of short lead-time capacity additions if public policy were revised to enable utilities to plan for their use. They would be a particularly valuable option where unanticipated capacity shortfalls occur.

Conclusions

In summary, although there is no current evidence that electricity demand will return to the runaway rates of growth of the 60s and 70s, it seems dangerous to assume a long-range future in which reliability will be achieved through extraordinary advances in conservation and peak load management. Long-term growth of electricity demand at rates between 50 and 100 percent of GNP growth are much more likely.

Such rates of growth inevitably will require a sustained program of generating capacity renewal and additions. The situation today will severely discourage utilities from pursuing an orderly construction program until the new demand growth is a matter of historical evidence. The lead times that seem to be unavoidably associated with conventional powerplant construction make this approach hazardous.

Some potentially desirable options for rapid reaction to unanticipated demand growth particularly utility sponsored cogeneration and gas-fired, combined-cycle powerplants, are currently constrained by public policy.

Finally, it is not clear today where the responsibility rests to plan for the future reliability of the U.S. electric power system. Utilities have been severely penalized for past errors of forecasting and overcommitment. Under current regulatory policies, the risk of investing in unneeded capacity is overwhelming.

It is less clear who bears the risk of shortages. Certainly, the burden of a shortage falls on the consumer in the form of industrial plant interruptions, personal inconvenience, and, in extreme situations, threats to public safety. But consumers in modern technological society cannot plan for electric reliability nor escape the impacts of shortfalls. Neither are their representatives in regulatory bodies notably well equipped and organized to plan utility programs.

The utilities themselves used to shoulder the responsibility to plan for reliable service. Today, as purchased power and non-utility decisions are substituted for generation, they have much less direct control over the evolution of their own systems. Additionally, the financial risk of doing business is heavily biased against construction.

The real problem facing the electric utility system today may most easily be characterized as a crisis in planning.

Addendum to the Prepared Testimony of
Daniel A. Dreyfus
Vice President
Strategic Analysis and Energy Forecasting
Gas Research Institute

before

The Committee on Energy and Natural Resources
United States Senate

Response to Committee Questions

By memorandum of July 16, 1985, the Committee staff requested witnesses to respond to seven specific questions. This addendum is to insure that my testimony addresses those questions.

1. Question: Will serious shortages of baseload generating capacity occur on individual utility systems by the early 1990s?

   Answer: Unless all currently planned utility construction programs remain on schedule, it is very likely that peak load shortages will become chronic in a number of systems by the mid-1990s.

2. Question: If such shortages occur, would each utility faced with such a shortage be able to prevent actual interruptions in service by obtaining additional supplies, such as combustion turbine generation or purchased power?

   Answer: The situation confronting each utility would be unique. It is unlikely, however, that widespread peak load shortages could be addressed by purchases of power. Once the situation is recognized, combustion turbines could be installed, assuming policy constraints on the use of new gas generation capacity were relieved. To achieve economic and efficient additions of gas-fired capacity rather than simply expedient peak shaving units would require a lead time of three years.

3. Question: In your forecast of electric power supply, what are the assumptions relating to the retirement schedule for existing generating plants?

   Answer: The 1984 GRI Baseline Projection assumes the retirement of major powerplants at rates derived from consideration of the expected useful life on a plant-by-plant basis. We are developing an approach to reflect the increasing probability that powerplant utilization will be extended indefinitely by major reconstruction.

   The average retirement ages we are currently using are as follows:

   Coal plants - 40 years
   Oil and gas plants - 45 years
   Nuclear plants - 40 years
   Hydroelectric plants - 100 years

4. Question: Do electric utilities have an incentive to minimize their investment in new central-station generating plants?

Answer: I have done no studies of the investment situation facing electric utilities, however, the general picture is clear. In the current conditions of high real interest rates and uncertain future financial circumstances, long-term investments of any kind are unattractive. Investors seek rapid recovery of their funds in order to make new decisions as conditions change. In effect, the discount rate is very high. Powerplants typically require large front end investments and are returned after a long delay and over a very long period. Equity investors, that is stockholders, would be well advised to avoid them unless the promised return was very high and the risk very low. In fact, despite recent improvements in rate of return allowed since 1970, stockholders in electric utilities have been receiving about 75 percent of the long-term return offered by general industrial stocks, and the risk in utility investment has grown immensely.

5. Question: If so, what are the factors contributing to the incentive?

Answer: Recent treatment of costs associated with cancelled or deferred powerplants and slow phase-in to the rate base of investment in completed plants add greatly to the risk of premature construction of new capacity.

6. Question: To what extent have so-called "rate suppression" decisions by some state public utility commissions increased the risk of future shortages of electric generating capacity?

Answer: I have not considered specific recent rate decisions concerning electric utilities.

7. Question: Who should have the responsibility for electric power supply planning, electric utilities or state regulatory commissions?

Answer: The planning of new power supplies must be done in association with the decision to make investments and in consideration of the risk and reward accruing from the investment. Traditionally, electric utilities planned for future power supplies. Their decisions were reviewed by public regulatory bodies to insure prudence. The utility accepted a responsibility to provide reliable, non-discriminatory service in return for a monopoly franchise to the service area. The uneconomic conditions placed upon the utility by various regulatory requirements were compensated for by an assurance that the ratepayers would bear the costs of service plus a fair rate of return on investments that were prudently made.

In current circumstances, utilities have been refused full anticipated compensation for past investments that have proven to be based upon errors of prediction, although the same errors were generally made in other contemporary public and private decisions. They have also been warned in many legislative and regulatory decisions that future overcommitment to capacity will be penalized heavily. In effect, the ratepayers have been relieved of a large portion of the risk burden associated with excess capacity.

Additionally, new nonregulated actors have been explicitly invited into the service areas without incurring a utility responsibility for either reliability of service or non-discriminatory service.

Although there is very little discussion of this issue, it appears that the utilities, in turn, are being relieved of the "utility responsibility" to provide service. The planning function, therefore, belongs to no one.

It is difficult to see how the regulatory bodies could plan for supply. The various commissions rarely coincide with appropriate physical planning regions. In most instances, they do not have the technical staff or budget necessary. In any case, once they come to a conclusion, they could only implement the plan by indirection. The utilities would still have to make the investment, and it would still have to be a viable financial undertaking considering the potential risks and rewards.

In my view, the traditional relationships should be preserved. More direct regulatory involvement in the endorsement of a planning projection, appropriate sharing of the risk of overinvestment, and some policy initiatives to facilitate rapid responses in the event of shortfalls might make the "utility responsibility" a reality once more.

POLICY IMPLICATIONS OF THE 1984 GRI BASELINE PROJECTION OF U.S. ENERGY SUPPLY AND DEMAND

1983–2010

Introduction

Natural gas will continue to maintain an important role in a highly competitive energy mix throughout the remainder of the century, according to the 1984 GRI Baseline Projection of U.S. Energy Supply and Demand. The baseline projection assumes steady economic growth at average historical rates, only moderate increases in the real dollar-denominated world price of oil, and no energy shortages. Continued conservation trends will moderate demand growth in all of the energy end-use sectors.

The annual baseline projection is the result of a complex modeling effort that integrates macroeconomic factors with specific economic factors relating to interfuel competition, sectoral energy demand and the supply of the various energy commodities, with particular reference to lower-48 hydrocarbon resource discovery and recovery economics. Through an iterative process, sectoral supply and demand balances are achieved that yield both energy quantities and market clearing-price levels, and incorporate the GRI management consensus on key policy and macroeconomic assumptions, including projected world oil price levels. The baseline projection attempts to describe how the U.S. energy future would evolve under these assumptions if observed technological trends continue and no credit is taken for the likely future impact of the GRI R&D program. This allows GRI to assess the potential benefits of specific new or improved technologies at various stages of the R&D and commercialization process against a consistent reference case.

The 1984 GRI Baseline Projection recognizes that important changes have taken place in energy markets since the previous projection was completed in 1983. As a consequence, the 1984 baseline contains lower gas, coal, and electricity prices, as well as lower petroleum product prices. The lower petroleum product prices result from assuming lower world crude oil prices — $30.68 per barrel in 1990, $39.27 per barrel in 2000, and $52.77 per barrel in 2010, when expressed in constant 1983 dollars.

The 1984 projection represents the initial effort to extend the projection to 2010. Although substantial revisions in the post-2000 years of the projection may be necessary as the projection is reviewed and discussed, an extended projection is necessary for GRI's internal analytical programs, particularly benefit analysis. There are trends within the projection that merit caution and consideration. Although they are credible and are consistent with the assumptions and analytical results, these trends lead to scenarios that suggest important potential planning or policy issues:

- Electricity is projected to increase its market share of delivered energy over the projection timeframe. This occurs as a result of the interaction of numerous market factors (e.g., comparative capital costs, gas hookup limitations, relative energy prices, etc.) that impact the competition between different energy technologies over the projection timeframe. To provide for the growth in electricity demand, substantial new electric generating capacity is required. Because of the diminished use of oil and natural gas in electricity generation and the projected relatively small growth in nuclear generation due to existing constraints, the predominant share of electric utility generation growth must be fueled by coal. The long lead times needed for coal-fired powerplant construction, possible acid rain legislation, and other physical and environmental considerations that constrain coal use, however, make realization of the required increase in electric generating capacity uncertain. These problems present the possibility for increased electricity generation through approaches using natural gas.

- The 1984 projection shows oil imports increasing to 7.3 million barrels per day in 2000 and 9.2 million barrels per day in 2010. This brackets the 1977 high of 8.8 million barrels per day. Increasing U.S. imports, if exacerbated by generally increasing global oil demand, could create a climate for higher-than-projected world petroleum prices, or even petroleum supply interruptions, leading to domestic policy initiatives to limit dependence upon imported oil. Such circumstances would provide natural gas with advantages in interfuel competition and would very likely expand the role of gas in the national energy mix beyond that projected in the 1984 GRI Baseline Projection.
- Even though increased opportunities for expanded gas consumption are indicated due to rising oil imports and concerns associated with the adequacy of future electric generating capacity, the projection shows that an expanded role for gas after the year 2000 is not probable without supplemental gas supplies based on new or improved technologies. In the post-2000 portion of the projection, the demand model exhausts the gas supplies provided at the then-prevailing average market clearing price, while there is still unfulfilled demand that could be captured by gas at this price. Independent GRI analyses indicate that new or improved technologies for recovery of unconventional natural gas from well-defined resources could provide as much as 2 Tcf per year of added production in 2010 at prices competitive with those projected for alternative fuels in the baseline projection.

Total Demand

Between 1983 and 2000, real GNP is projected to grow at 2.8% per year. Total energy consumption is projected to grow from 74.1 quads in 1983 to 96.7 quads in 2000 (Exhibit 1), or at 1.6% per year. Thus, energy consumption grows at approximately one-half the rate of GNP (57.1%) over the projection.

Exhibit 1

PRIMARY ENERGY CONSUMPTION
1984 GRI Baseline Projection

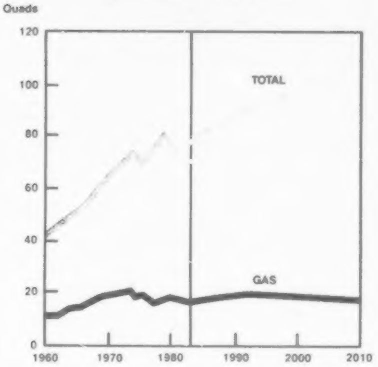


Exhibit 2 shows a breakdown of U.S. primary energy consumption by fuel type.

Exhibit 2

U.S. PRIMARY ENERGY CONSUMPTION
1984 GRI Baseline Projection
(Quads)

	1983	1990	2000	2010
Petroleum	30.0	32.2	33.6	35.7
Gas	17.4	19.5	19.4	17.0
(Total Gas Fuels)	(17.5)	(19.6)	(19.7)	(17.8)
Coal	15.8	19.3	26.9	35.9
Nuclear	3.2	6.2	6.6	5.6
Hydro	3.8	3.8	3.9	4.0
Renewables	3.9	5.0	6.3	8.7
Total	74.1	86.0	96.7	106.9

Petroleum consumption is projected to grow 1.0% per year between 1983 and 1990 and at a slower 0.4% per year between 1990 and 2000. The higher level of growth in the 1980s reflects a rapid growth in industrial petroleum consumption between 1983 and 1990, much of it for feedstock uses.

Primary gas demand is expected to increase from 17.4 quads in 1983 to 19.4 quads in 2000. "Total gas fuels" includes synthetic natural gas as well as primary gas consumption.

Throughout the entire projection, coal has an economic advantage over oil and gas in industrial applications. Although its use is constrained by physical and regulatory limitations, coal progressively gains in its share of new demand over the term of the projection. Coal is expected to account for the largest portion of new growth in industrial fuel and power consumption, growing from 1.5 quads in 1983 to 3.5 quads in 2000. Coal is also the predominant fuel for new electric generating capacity, with consumption projected to grow from 13.2 quads in 1983 to 21.7 quads in 2000.

Nuclear energy grows from 3.2 quads in 1983 to 6.6 quads in 2000. The projection of nuclear energy amounts to about 111 gigawatts of on-line capacity by 2000. The projection assumes that, out of the 125 gigawatts of capacity currently considered to be "on order," further nuclear plants will be deferred or cancelled. No new orders for nuclear plants are included in the projection.

Base-year total renewable energy consumption (in addition to hydropower) has been derived from numerous published sources. The 1983 base-year total for renewable energy consumption of 3.9 quads includes 2.3 quads of wood consumption and 1.6 quads of "other" consumption (geothermal, waste, biomass, solar, etc.). Total renewable energy consumption is expected to grow from 3.9 quads in 1983 to 6.3 quads in 2000.

Gas Demand

A summary of gas demand by sector is shown in Exhibit 3.

Exhibit 3

GAS DEMAND BY SECTOR
1984 GRI Baseline Projection
(Quads)

	Actual 1983	1990	2000	2010
Residential	4.6[a]	4.5	4.3	3.9
Commercial	2.6[a]	2.8	3.5	4.5
Industrial	6.7	7.7	8.3	6.2
Electric Generation	3.0	3.9	2.6	2.1
Transportation[b]	0.6	0.7	1.0	1.1
Total[c]	17.5	19.6	19.7	17.8

a Historic Energy Information Administration (EIA) statistics for 1983 do not disaggregate data for the residential and commercial sectors.
b Includes 0.3 and 0.5 quad of demand by methane vehicles in 2000 and 2010, respectively.
c Includes 0.1, 0.3 and 0.8 quad of synthetic gas from petroleum and coal in 1990, 2000 and 2010, respectively.

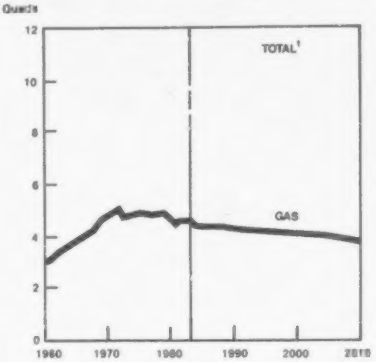
Residential

Exhibit 4 shows that residential sector (including both multi- and single-family units) gas demand is projected to fall from 4.6 quads in 1983 to 4.3 quads in 2000, although total residential energy consumption is projected to grow from 9.5 quads in 1983 to 10.6 quads in 2000. The decline in gas demand, due to conservation, is projected to occur in spite of a projected increase in the number of gas-heated dwelling units from 44 million to 54.7 million. Conservation of all delivered energy sources in the residential sector, including renewables, occurs at a rate of 1% per year from 1983 to 2000.

The growth in the gas share of new construction, combined with conversions of oil systems to gas, is projected to enable gas to maintain a relatively constant 57% share of the single-family home heating market through 2000. However, the gas share of the multifamily home heating market falls from 44.5% in 1983 to 43.1% by 2000 due to a decline in the gas share of new multifamily housing.

Exhibit 4

RESIDENTIAL ENERGY CONSUMPTION
1984 GRI Baseline Projection



¹ The projection includes renewable energy consumption which is not accounted for in historical data.

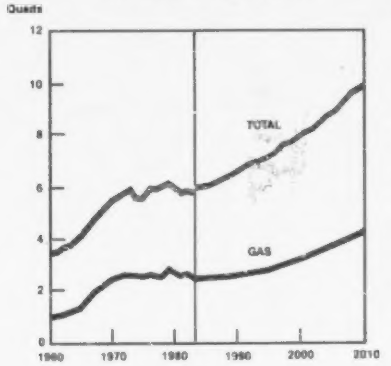
The growth in projected total residential energy consumption results from growth in electricity and renewable energy consumption, which more than offset conservation and the declines in gas and oil consumption. Residential electricity consumption grows from 2.6 quads in 1983 to 4.0 quads by 2000, and renewable energy consumption grows from 0.9 quads to 1.3 quads.

Commercial

Total energy consumption in the commercial sector is projected to grow rapidly over the projection timeframe, due to the continued rapid expansion of commercial

Exhibit 5

COMMERCIAL ENERGY CONSUMPTION
1984 GRI Baseline Projection



square footage at a rate of 3.1% per year (Exhibit 5). Unlike the residential sector, gas and electricity equally share the majority of the growth in commercial and energy demand—0.9 quads each from 1983 to 2000.

Nearly one-half of the growth in commercial gas consumption from 2.6 quads to 3.5 quads is for uses other than space heating (e.g., water heating, cooking, and cooling). Nonspace heating-related uses of natural gas grow from an estimated 0.5 quad in 1983 to 0.9 quad in 2000. Gas consumption for water heating is projected to grow from 0.3 quad in 1983 to 0.5 quad in 2000.

No estimate of cogeneration in the commercial sector is included in the 1984 projection. While cogeneration has significant potential in the commercial sector, data concerning market penetration, economics, or potential technologies are not readily available.

Industrial

Although total industrial energy demand is projected to increase from 22.1 quads in 1983 to 30.9 quads in 2000, and gas consumption is projected to increase from 6.7 quads in 1983 to 8.3 quads in 2000 (Exhibit 6) the gas share of total industrial energy consumption is projected to fall from 30% in 1983 to 27% in 2000.

Industrial gas consumption for fuel and power uses is projected to gradually increase from the extremely low level of consumption in 1983 (6.1 quads), reaching 7.2 quads in 1990 and 7.8 quads by 2000. Growth in gas consumption after 1990 is slower than that in the 1980s as a result of increased penetration by coal in industrial boiler markets and increased use of electricity in direct-heat applications.

Industrial gas consumption for cogeneration rises rapidly over the projection timeframe. It grows from approximately 0.3 quad in 1983 to 0.5 quad in 1990 and 0.7 quad in 2000.

Electricity Generation

The 1984 baseline projects a declining share of gas in *central* power generation, although central generation of electricity represents an increasing portion of total primary energy consumption over the projection period (Exhibit 7). It grows from 33.6% of total primary energy consumption in 1983 to 38.7% in 2000. While energy consumption for electricity generation is projected to continue to grow over the projection period, both in aggregate and as a percentage of total primary energy consumption, the projected growth rates are less than historic norms. If electricity produced through industrial cogeneration is included, electricity consumption grows at 2.4% per year between 1983 and 2000. GNP grows at 2.8% per year over the same period. Therefore, electricity consumption is projected to grow at 85.7% of the rate of GNP over the projection timeframe.

Gas consumption for *central* electrical generation is projected to reach a high of 3.9 quads in 1990 and then slowly decline to 2.6 quads by 2000. Projected gas consumption is almost entirely associated with existing gas-fired power plants. By 2000, the majority of gas consumption is for peaking purposes only.

Exhibit 6

INDUSTRIAL ENERGY CONSUMPTION
1984 GRI Baseline Projection

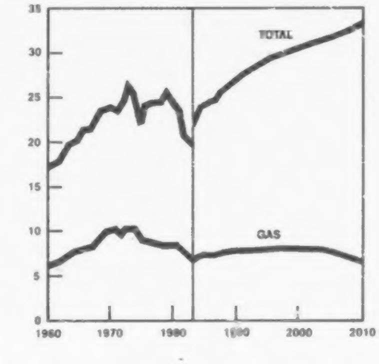


Exhibit 7

ELECTRIC UTILITY ENERGY CONSUMPTION
1984 GRI Baseline Projection

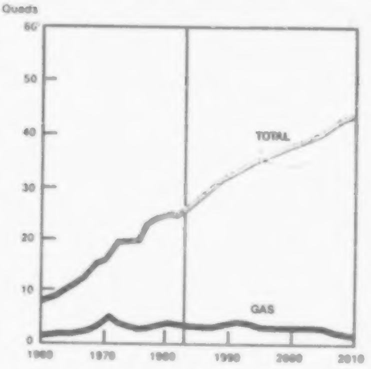
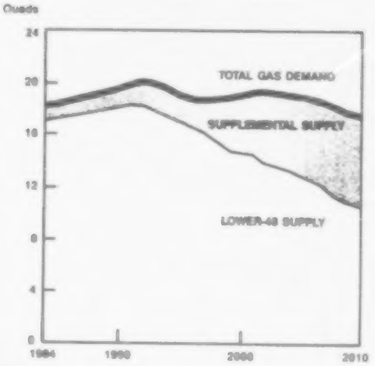


Exhibit 8

GAS SUPPLY
1984 GRI Baseline Projection



Gas Supply

For purposes of planning GRI's program, two of the most critical variables for an energy-economic projection are the gas supply quantities and associated prices. Exhibit 8 illustrates that supplemental gas supplies will provide an increasing share of gas supply over time as a result of declining lower-48 gas production. Supplements served about 6% of U.S. gas consumption in 1983. By 2000, supplements are projected to provide almost 25% of U.S. gas supply and, by 2010, they are projected to provide 40% of U.S. gas supply.

Exhibit 9 summarizes the gas supply quantities and prices that are associated with the 1984 projection. The "natural gas" quantities include conventional lower-48 production; unconventional production that is not dependent upon presently unproved, or yet to be developed, technologies; and small amounts of gas produced and consumed in Alaska. Natural gas prices and supplies are based on analyses using the GRI Hydrocarbon Model. The average prices for natural gas were developed assuming that the Natural Gas Policy Act of 1978 continued in effect as enacted. Prices for unregulated new gas were developed to reflect the costs of production projected by the GRI Hydrocarbon Model.

The projected supplies and prices of gas other than lower-48 conventional and unconventional natural gas production are not an outcome of the economic modeling exercises but are based on exogenous inputs or assumptions. Specifically, the Alaska natural gas pipeline is assumed to begin operation in 1998. By 2000, the baseline projects that the Alaska Natural Gas Transportation System will be supplying 0.7 quad. ANGTS prices are based on the most recent statements of the pipeline consortium and on a revenue requirement analysis prepared by GRI. They are not based upon levelized cost and, therefore, indicate high front-end capital costs in the early years of operation.

Real prices for pipeline imports at the border are projected to decrease until they equal the marginal price for lower-48 production. Thereafter, they increase with the marginal price of lower-48 gas production. The large growth in pipeline imports during the 1990s implies that some supplies begin to appear from new Canadian-producing regions (e.g., MacKenzie Delta, Atlantic), and that Mexican gas exports to the United States begin to grow.

LNG imports are projected to grow from 0.2 quad in 1990 to 0.7 quad in 2000. The projection assumes that Algerian LNG contracts would not be renegotiated. LNG from other areas, such as Alaska and Indonesia, is assumed to be priced competitively with natural gas and pipeline imports.

Coal gasification is projected to supply less than 50 Bcf in 1990 and 0.1 quad in 2000. The projection assumes that only three half-scale coal gasification plants will be completed by the year 2000. This is due to the availability of lower-cost lower-48 natural gas and natural gas imports. Costs are based upon revenue requirements for the projects and industry capital-cost estimates.

Exhibit 9

GAS SUPPLY AND PRICE TRENDS
1984 GRI Baseline Projection

	1990		2000	
	Supply (Quads)	Acquisition Price (1983$/MMBtu)	Supply (Quads)	Acquisition Price (1983$/MMBtu)
Natural Gas	18.2	3.70	14.9	5.19
ANGTS Gas	—	—	0.7	9.64
Pipeline Imports	1.1	3.92	3.1	6.11
LNG Imports	0.2	6.65	0.7	6.53
Coal Gas	a	7.26	0.1	9.02
SNG From Petroleum	0.1	6.04	0.2	7.73
Total Delivered	19.6	3.76	19.7	5.58
Unaccounted for Losses and Exports	0.6		0.6	
Total Supply	20.2		20.3	

a Less Than 50 Bcf

Issues

While the GRI baseline projection is used by GRI as a strategic planning tool to evaluate the potential impact of GRI's R&D program, the projection reveals a number of significant issues that are of interest not only to GRI, but to policy makers, energy companies, and others involved in energy markets. In the 1984 projection, three issues were particularly highlighted by the extension of the trend to the year 2010 for the first time: the outlook for liquid fuels, electricity, and longer-term gas supplies.

Liquid Fuels Outlook

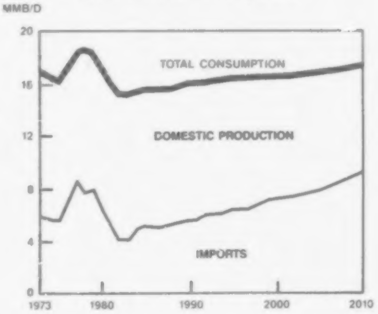
A major issue highlighted by the 1984 projection is the increasing total demand for liquid fuels and oil imports (Exhibit 10). The 1984 GRI Baseline Projection estimates that U.S. primary energy consumption will reach nearly 107 quads in the year 2010, with petroleum contributing 33% (35 quads) of the total. By comparison, in 1983 the U.S. consumed 30 quads of petroleum, which accounted for 40% of total primary energy.

Petroleum consumption is forecast to increase from 15.2 million barrels per day in 1983 to 16.7 million barrels per day in 2000. In the extended projection, petroleum consumption reached 17.6 million barrels per day by 2010. This is consistent with the assumption of relatively moderate increases in the world oil price and adequate world oil supplies.

While domestic consumption is increasing, the domestic production of crude is expected to decline throughout the projection to 7.8 million barrels per day in 2000.

Exhibit 10

TOTAL U.S. PETROLEUM
CONSUMPTION, PRODUCTION, AND IMPORTS
(1973–2010)
1984 GRI Baseline Projection



a reduction of nearly a million barrels per day from today's production levels. The baseline projection, when compared to forecasts of the major oil companies and to other independent GRI analyses, is relatively optimistic concerning U.S. crude oil production. The oil companies expect domestic crude production to decline faster between 1983 and 2000 to, on average, around 6.5 million barrels per day in 2000.

The net result of an increasing demand for petroleum, with a simultaneous decline in domestic crude production, is an increased dependence on foreign sources of crude. The baseline projection expects imports to increase to 9.2 million barrels per day in 2010, the greatest demand for imports since the 1977 high of 8.8 million barrels per day. The lower estimates of U.S. crude production from the oil companies would result in even higher levels of imports on the assumption of unchanged and uniform world oil prices because the total U.S. demand for petroleum projected would then be unaffected.

Today, the U.S. is importing the majority of its crude and petroleum products from non-OPEC countries, particularly Canada and Mexico. However, as the global economy expands in the near term and domestic production declines, the OPEC nations will become the incremental suppliers, with their production rising from the current 17.5 million barrels per day, only about 60% of its productive capability. As the U.S., and presumably the rest of the noncommunist world, demands even greater quantities of imported oil, the OPEC nations will become more dominant suppliers than today. Both Chevron and Conoco foresee OPEC production increasing to 21.5 million barrels per day in 1990 and to nearly 29 million barrels per day in 2000.

It seems probable that the leading producers will require significant premiums in real terms to provide increases in production beyond that which is sufficient to provide for their own revenue requirements. As a result, the world price for crude may escalate at a rate greater than that assumed in the baseline projection (the baseline price of crude oil in 1983 dollars per barrel is $39.27 and $52.77 in 2000 and 2010, respectively).

The United States has reduced its dependence on Arab-OPEC oil since the supply disruption of 1979 by importing greater quantities of non-OPEC and non-Arab OPEC oil. However, by the 1990s, the United States will no longer have this option since the non-OPEC countries will face declining production levels. As a result, the U.S. may be faced with the prospect of again relying on OPEC oil from the potentially unstable countries of the Middle East as the major source of its crude oil imports.

Electrical Outlook

The 1984 baseline projection indicates an increasing role for electricity in future energy markets. Electricity is projected to increase its market share of delivered energy from 13% in 1983 to 16% by 2000. With the projected diminished use of oil and natural gas in electricity generation and the projected relatively small growth in nuclear generation due to existing constraints, the predominant share of electric utility generation growth must be fueled by coal.

The 1984 baseline projection indicates that a total of 181 million kilowatts of new capacity additions will be required by 2000 to meet the projected end-use electricity demand in the baseline projection. Approximately 134 million kilowatts of this additional capacity is required by 1995, which is only 11 years away, less than the current average construction lead time for a major new coal unit.

According to 1983 Energy Information Administration data, capacity additions either currently under construction or planned would add 141 million kilowatts of capacity by 1995. However, recent trends indicate that many of the plants included in these planned additions may not be constructed. For example, 61 million kilowatts of nuclear capacity additions are included in the current plans. It is unlikely, given recent trends, that all of the 61 million kilowatts will be completed. The 1984 baseline projection assumes that only 36 million kilowatts of additional nuclear capacity will be constructed over the projection timeframe. The anticipated shortfall would have to be made up by alternative new generating capacity, presumably coal. Further, of the 65 million kilowatts of new coal capacity included in the currently planned 141 million kilowatts, construction of over 20 million kilowatts has not actually been started. Given these assumptions and the long lead time currently associated with construction of new generating capacity, it appears possible that currently planned additions to generating capacity may not be sufficient to satisfy projected end-use electricity demand in the mid-1990s.

Compounding the uncertainty associated with the ability of the electric utility industry to construct the necessary generating capacity is the current policy debate over clean air standards, especially the threat of acid rain mitigation measures. It is quite likely that the requirement for new generating capacity will have to be implemented in the face of, at best, more costly pollution measures or, at worst, outright physical limitations on the operation of coal-fired equipment.

If electrical demand, in fact, increases at rates equal to or greater than those contemplated in the 1984 GRI Baseline Projection, it is probable that the electric utility industry will confront serious problems in meeting the requirements for new generating capacity beginning in the early 1990s.

The baseline projection already assumes strong improvements in energy conservation, and there are few other alternatives available to utilities to cope with the problems. The most likely alternative approaches that might offer large-scale contributions to electric generating capacity could also significantly increase the use of natural gas by utilities.

One approach would be to generate an increased share of the required electricity at, or near, the point of demand in cogeneration facilities, thus optimizing the use of the gas transmission and distribution systems and reducing or postponing the need for new large-scale electric generating capacity. Another approach would be to construct efficient, gas-fired combined-cycle power plants in place of some coal-fired generation. This approach could reduce the lead time required, simplify siting considerations, and reduce the size of new increments of generating capacity.

Therefore, natural gas could be called upon to play an expanded role in the utility sector beyond that currently contemplated in the 1984 baseline projection.

Post-2000 Gas Supply

In the post-2000 period, the baseline projection shows gas consumption declining sharply as a result of a restriction on the amount of gas considered to be available from lower-48 production and conventional supplemental supplies (such as pipeline imports) at prices competitive with alternative energy sources. Through the 1980s and 1990s, gas consumption remains relatively level at about 19.5 quads. However, after 2000, gas consumption falls off sharply, reaching 17.9 quads in 2010.

Supplies based on new or improved technologies, such as incremental production from tight formations made available by research and development carried on in, or in association with, the GRI program or by others and advanced synthetic gas technologies that are associated with GRI R&D and other efforts on a worldwide basis, are not assumed in the GRI baseline projection. In the absence of these sources, the demand model exhausts the gas supplies provided while there is still unfulfilled demand in the industrial sector that could be captured by gas at the then-current average gas price.

Analyses made for the GRI R&D program indicate that new technologies could become available during the term of the projection as the result of GRI programs and associated R&D activities. These technologies could contribute annual supplies of 2 Tcf or more by 2010 primarily through incremental production of lower-48 gas from tight formations at prices competitive with the projected average gas prices used in the 1984 GRI Baseline Projection. If such new technology-based supplies did become available after 2000, U.S. gas demand would remain at about 19.6 quads.

As projected, without incremental new technology-based supplies, supplemental gas supplies (e.g., pipeline imports, LNG, Alaska deliveries to the lower-48 states, coal gas, SNG from petroleum) would have to provide a rapidly increasing share of gas supply over time as the result of declining lower-48 gas production in the post-2000 period.

The contributions that can be expected from these supplemental sources at prices competitive with alternative energy sources become the limiting factor upon the use of gaseous fuels in the industrial sector. There is a need, therefore, for substantial amounts of new technology-based gas supplies in the post-2000 period. If these supplies are forthcoming at competitive prices, the role of gas in post-2000 energy markets could be greater than that shown in the baseline projection.

Conclusion

The 1984 GRI Baseline Projection of U.S. Energy Supply and Demand portrays a long-range scenario of generally strong economic growth, no energy supply shortfalls in this century, and only moderate escalation in the real prices of all major energy sources. Natural gas will continue to maintain an important role in a highly competitive energy mix throughout the remainder of the century.

While the baseline projection is used by GRI as a strategic planning tool to evaluate the potential impact of GRI's R&D program, it also reveals a number of significant issues that are of importance not only to GRI, but to policy makers, energy companies, and others involved in energy markets. The difficulties in building the number of coal-fired power plants required to meet projected electricity demand, the increasing level of oil imports, and the unfulfilled gas energy demand after 2000 — all provide opportunities for the increased use of natural gas.

Independent GRI analyses indicate that new or improved technologies in unconventional natural gas could provide as much as 2 Tcf per year of added production in 2010 at competitive prices. If such new technology-based supplies were available after 2000, U.S. gas demand could remain at about 19.5 quads per year through the first decade of the 21st century.

Full Report Available

This summary is based on the 1984 GRI Baseline Projection of U.S. Energy Supply and Demand prepared by Paul D. Holtberg, Thomas J. Woods, and Anne B. Ashby of GRI's Strategic Analysis and Energy Forecasting Division. The full report presents a series of summary tables, sectoral breakdowns, the natural gas supply and price trends from the projection, and a comparison with GRI's previous baseline projection. The appendices include a discussion of the methodology and assumptions used to prepare the 1984 projection and provide additional data and discussion on selected energy issues.

Questions or comments concerning the 1984 GRI Baseline Projection should be directed to GRI's Strategic Analysis and Energy Forecasting Division located at 1019 19th Street, N.W., Suite 615, Washington, D.C. 20036; telephone: (202) 785-3409.

Senator EVANS [presiding]. Thank you, Dr. Dreyfus. The answers to those questions will be made a part of the record.

Dr. Hogan.

STATEMENT OF DR. WILLIAM W. HOGAN, DIRECTOR, ENERGY AND ENVIRONMENTAL POLICY CENTER, JOHN F. KENNEDY SCHOOL OF GOVERNMENT, HARVARD UNIVERSITY

Dr. HOGAN. Thank you, Mr. Chairman. It's a pleasure for me to have an opportunity to address the committee today.

My name is William W. Hogan and I'm a professor at the Kennedy School of Government at Harvard University and a director of the Energy and Environmental Policy Center.

I prepared a written testimony which I submitted in advance, and in the interest of time and especially given the excellent summary and overview that the previous speaker, Dan Dreyfus, just offered, I think it would be appropriate for me to summarize my testimony, and especially highlighting any added points that I might want to make that would be relevant for your discussions.

Senator EVANS. Please do. The full statement of all the panel will be included in the record.

Dr. HOGAN. Thank you, Mr. Chairman.

My own studies of energy demand over the years have focused on the opposite approach to that described by Dan Dreyfus. He mentioned a top-down approach with aggregate data based on historical correlations and the more detailed end use or bottom-up approach that he uses. My work is concentrated on the top-down approach and complements his own studies.

In particular, what I've attempted to do is to look at a relatively straightforward description of the evolution of energy demand and electricity demand and to examine the question as to how far we can go in explaining the historical data with a simple description that it depends upon the relationships to economic activity and the prices of the key energy products.

I've been especially interested to what extent we might need to look at sudden shifts in the energy economy to explain the historical data, the need to appeal to regulatory programs in order to explain the historical data, and so on. So I've looked at the dynamics of energy adjustment and the data base that comes from the Department of Energy over the period 1960 to 1982.

What I have found is that we do not need more complicated views of the world to explain at least the historical changes in energy demand. Rather, four factors seem to be adequate to at least track what has happened historically and are suggestive of what we might see in the future.

First, inter-fuel substitution has caused significant change in the mix of fuels used to provide energy services. The principal effect of the substitution historically has been the continued electrification of the economy over a span of decades. This is a trend which slowed, but was not eliminated even during the seventies.

Second, energy conservation has led to major improvements in energy efficiency in homes and factories. The potential long-term efficiency in energy use per unit of activity is amongst the most important avenues for improving the productivity of our economy.

My own work suggests that the price increases since 1972, the energy price increases, have created the potential for an eventual reduction in energy use per unit of activity of up to 40 to 50 percent across the board, and this improvement is only partially complete today.

Third, changes in the level of economic activity have immediate and incremental effects on energy and electricity demand. Hence, in 1984 when the economy grew at just under seven percent we saw significant increases in energy use that almost matched the total growth of the economy.

Finally, all of these factors—inter-fuel substitution, energy conservation, and economic growth—combine through a slow pattern of adjustment. Energy efficiency changes take place principally through the installation of new capital stock. Hence the data include a complicated overlay of adjustments to the price shocks of 1972 and 1973 and then of 1980, with the—coupled with the movements in the business cycle.

This slow adjustment and the succession of shocks makes particularly difficult a separation of the individual factors, either to explain history or to project the future. The details of my analysis are contained in a paper which I have attached to my testimony, entitled "Energy Demand and the Outlook for Electricity." The conclusions I come to for the purposes of today's discussion are as follows.

First, the data from 1960 through 1982 are consistent with the simple hypotheses of large long-run conservation potential, but slow adjustment of both energy efficiency and inter-fuel substitution.

Second, the adjustment process is not complete and for the next several years, even with no further changes in prices, we would anticipate relatively slow growth in energy and electricity demand.

However, thirdly, under the assumptions used by the Department of Energy, with the revival of oil prices in the 1990's, we would see a turnaround where electricity demand would grow more rapidly than the economy.

And fourth, even the best estimates of electricity demand are clouded by uncertainty, as you pointed out, Senator Evans. For aggregate electricity demand from 1990 to 2000, for example, my calculations suggest that there is a significant chance of growth being less than 2 percent per year or more than 4 percent per year.

One of the things that I have attempted to do in the paper is to provide an example of how to quantify both that range and the likelihood of it occurring. Hence, the principal lessons for forecasting and planning are to expect possible changes in the nineties, but recognize the importance of uncertainty in modifying present planning decisions.

What would be especially of concern for the purposes of this discussion is the possibility that we could have relativey slow electricity growth for the next several years as we continued to work out the conservation effects because of the recent price shocks, and then suddenly accelerated growth as the oil market turns around in the 1990's, which would complicate the planning and lead time problems that the facilities would face.

Of course, given the nature of the hearings and the concern about meeting energy and electricity demand, we should remember—and I emphasize, as Senator McClure said in his opening remarks—the experience of the last decade and avoid overstating the difficulties of possible increases in demand.

Changes in the growth of energy demand will be matched by changes in prices and supply. The system will most likely balance over time if utility managers are doing their job. We're not likely to face widespread curtailments. The principal question for policy planning and the proper focus, as I see, of this hearing is the degree to which we can keep the costs under control as we adjust our system to balance demand and the degree to which utility executives have the ability to try to minimize those costs.

I have submitted the detailed paper of my comparative study of energy and electricity demand forecasts for the record, and I would be happy to address any questions from the committee. And I thank you again for letting me appear today.

[The prepared statement of Dr. Hogan follows:]

WILLIAM W. HOGAN

TESTIMONY

Committee on Energy and Natural Resources
of the
United States Senate

July 23, 1985

Good morning, Mr. Chairman. It is a pleasure for me to have an opportunity to address the Committee today. My name is William W. Hogan. I am a Professor of Political Economy, Chairman of the Public Policy Program, and Director of the Energy and Environmental Policy Center at the John F. Kennedy School of Government, Harvard University. In addition, I am a Director of Putnam, Hayes & Bartlett, Inc. (PHB), an economic and management consulting firm located in Cambridge, Massachusetts. I also serve as the President of the International Association of Energy Economists. Formerly, I was Deputy Assistant Administrator for Data and Analysis in the Federal Energy Administration. In my research and general writings on national energy policy, I have reviewed analyses and forecasts of the changing patterns of energy use. My testimony provides a summary of these continuing studies with an emphasis on the demand for electricity.

My own examination of electricity and energy demand has concentrated on analyses of the aggregate data. My purpose is to provide an overview and framework for review of the major forces affecting demand and their relationships to the historical data. This work complements more detailed econometric studies and end use demand models that can provide valuable insights in sectoral analysis and in the study of particular technologies.

A central question in my review has been the extent to which there may have been these major shifts in the patterns of energy demand other than those that can be explained by basic economic variables such as the GNP and the price of key energy products. As you know, the slow recognition of the conservation ethic led to a transformation in energy forecasts. Often we hear that the energy shocks changed forever the nature of energy in the economy, implying that the historical data before the energy shocks was not consistent with our more recent experience. My own work suggests that we do not need this more complicated view to explain the changes in energy demand. Rather my study emphasizes four factors that have been consistent over the period 1960 - 1982.

First, interfuel substitution has caused significant change in the mix of fuels used to provide energy service. The principal effect of the substitution has been the continued electrification of the economy over a span of decades.

Second, energy conservation has led to major improvements in energy efficiency in homes and factories. The potential for long-run efficiency in energy use per unit of activity is among the most important avenues for improving the productivity of our economy. My own work suggests that the price increases since 1972 have created the potential for a total reduction in energy use per unit of activity of up to 40-50%, and this improvement is only partially complete.

Third, changes in the level of economic activity have immediate and incremental effects on energy and electricity demand. Hence in 1984, when the economy grew at just under 7%, we saw significant increases in energy use that almost matched the total growth in the economy.

Finally, all of these factors, interfuel substitution, energy conservation and economic growth combine through a slow pattern of adjustment. Energy efficiency changes take place principally through the installation of new capital stock. Hence the data include a complicated overlay of adjustments to the price shocks of 1972 and 1980 coupled with the movements in the business cycle. This slow adjustment and succession of shocks make particularly difficult the separation of the individual factors either to explain history or to project the future.

The details of my analysis are contained in the attached paper, "Energy Demand and the Outlook for Electricity," which I submitted for the record. The conclusions of this analysis are

1) the data from 1960 through 1982 are consistent with the simple hypotheses of large, long-run conservation potential but slow adjustment of both energy efficiency and interfuel substitution.

2) The adjustment process is not complete and for the next several years, even with no further changes in prices, we would anticipate relatively slow growth in energy and electricity demand.

3) However, under the assumptions used by the Department of Energy, with the revival of oil prices in the 1990s, we could see a turnaround where electricity demand grows more rapidly than the economy.

4)Even the best estimates of electricity demand are clouded by uncertainty. For aggregate electricity demand from 1990 to 2000, there is a significant chance of growth being less than 2% or more than 4% per year. Hence the principal lesson for forecasting and planning are to expect possible changes in the 1990s but recognize the importance of uncertainty in modifying present planning decisions.

Finally, given the nature of the hearings and the concern about meeting energy and electricity demand, we should remember the experience of the last decade and avoid overstating the difficulties of possible increase in demand. Changes in the growth of energy demand will be matched by changes in prices and supply. The system will balance over time. We are not likely to face widespread curtailments. The principal question for policy planning is the degree to which we can keep costs under control as we adjust our system to balance with demand.

I have submitted the detailed paper on my comparative study of energy and electricity demand forecasts. I am happy to address any questions from the Committee. Thank you for letting me appear today.

ENERGY DEMAND
AND THE
OUTLOOK FOR ELECTRICITY

July, 1985

by

William W. Hogan

Putnam, Hayes and Bartlett, Inc.
Cambridge, MA
&
Energy and Environmental Policy Center
Kennedy School of Government
Harvard University

Energy Demand
and the
Outlook for Electricity[1]

INTRODUCTION

The outlook for electricity consumption remains a contentious issue with implications for long-lived capital investments. Inherent in any assessment of the outlook for electricity we find a parallel review of the wider energy market, and the analysis of the patterns of energy use presents a continuing process of change. The price shocks of the energy decade created a history of interrupted growth in energy demand. The dramatic reduction in the intensity of energy use broke the long connection between energy consumption and economic performance. International comparisons and engineering studies revealed the great potential for modifying the use of all forms of energy in conjunction with other economic inputs.[2] Faced with unstable market conditions, planners in industry and government scrambled to rethink and rearrange their energy strategies to accomodate both the new economics and the new risks of energy use.

No sooner had one shock abated during the 1970s than a new disturbance appeared. Hence we have faced the challenge of separating the transient from the permanent, to link the short-run adjustment to the long-run equilibrium. The upshot of the turmoil has been a continuing debate over the most likely prognosis for the development of energy and electricity demand. In this paper we summarize one approach to a continuing analysis of energy demand. Here we emphasize the importance of slow achievement of large long-run adjustments, with special attention to the implications for electricity consumption. Within this framework, we can explain the past and see how the future can differ from the current trends as much as the present differs from the past.

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[1] Paul Leiby provided valuable assistance in the preparation of this analysis. This paper is based in part on a presentation given to the Synfuels '85 Conference, April 12, 1985.

[2] For a review of energy conservation studies, international comparisons and engineering analyses during the energy decade, see J. Sawhill, Energy Conservation and Public Policy, Prenctice-Hall, 1979.

PIERCING THE NERC FAN

By now the infamous "NERC Fan" has come to embody one end of the spectrum of popular wisdom about the dangers of forecasting. From 1973 on, the North American Electric Reliability Council (NERC) reduced its projection of future demand for electricity. For ten years in succession, the effects of energy conservation and reduced economic growth led the NERC to acknowledge a consistent overestimate of electricity demand.[3] The resulting comparison of revised forecasts resembles a spreading fan, as shown in Figure 1. Of course, we emphasize the NERC results only because they are better documented, not because the experience is exceptional. The NERC summary forecast reflects the general experience of load forecasters in individual utilities, where incentives mounted to avoid yet again another projection on the high side. By the early 1980s, the "low growth" scenarios emphasizing the power of energy

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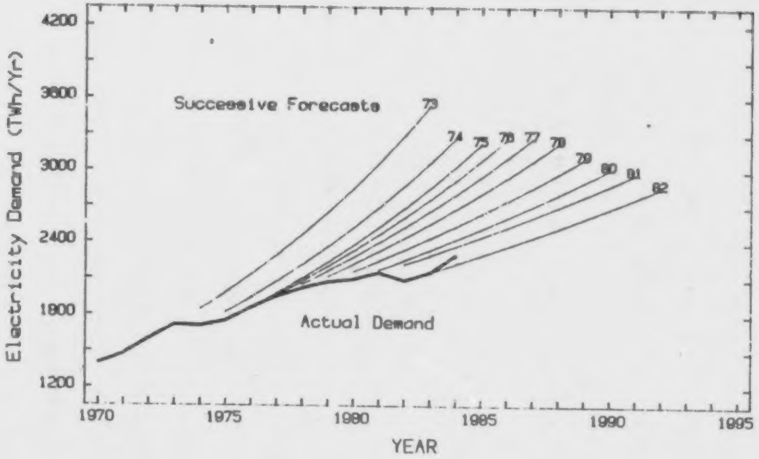
[3] For a detailed review of the NERC forecasts and comparison with alternative analytical approaches, see C. R. Nelson and S. C. Peck, "The NERC Fan: A Retrospective Analysis of the NERC Summary Forecasts," Electric Power Research Institute, Mimeo, January 1985.

Figure 1

HAVE WE PIERCED THE NERC FAN?

Projected Electricity Demand (TWh/Yr)



Note: North American Electric Reliability Council (NERC) Forecasts taken from summary by Nelson and Peck, 1985. Actual Electricty Use from Energy Information Administration, US Department of Energy.

Draft 5-18-85

conservation had become the new conventional wisdom.[4]

The strategic importance of energy conservation has been reinforced by the financial problems of the electric utility industry. With rising costs and lower load growth, the accumulated excess of generation capacity resulted in power plant cancellations that matched new orders for almost a decade of zero net additions. The costs of abandoned and deferred plants created the specter of higher prices depressing demand in a further downward spiral of permanently falling revenues.[5] Unwilling to risk being stuck with unwanted plants, utilities have entered a long period of working off excess capacity.[6]

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[4] For an example of the case for low growth coupled with the pursuit of energy conservation to reduce the cost of meeting demand for energy services, see R. F. Naill and R. W. Sant, "Electricity Markets in the 1990s: Feast or Famine?", Public Utilities Fortnightly, April 26, 1984, pp. 19-24; P. A Carlson, "Electricity versus Gross National Product Growth", Public Utilities Fortnightly, January 10, 1985, pp. 40-41. Putnam, Hayes and Bartlett, Inc. examined the implicit assumptions that imply higher electricity demand coupled with lower overall energy use in Alternative Energy Futures: A Review of Low Energy Growth Forecasts and Least-Cost Planning Studies. Report to Department of Energy, Cambridge, MA, November 1982 (Revised June 1983). An overview of several forecasts and their implications appeared in F. P. Sioshansi, "Outlook for Electricity: The Emergence of New Trends," Paper at the IAEE meeting, Washington, DC, June 1983. Amory Lovins examined the tremendous technical potential for electricity conservation in "Saving Gigabucks with Negawatts," Public Utilities Fortnightly, March 21, 1985, pp. 19-26.

[5] Lovins, "Saving Gigabucks with Negawatts." The costs of long delayed nuclear plants present a great challenge to the industry; see J. Cook, "Nuclear Follies," Forbes, February 11, 1985, pp. 82-100. R. L. Itteilag and J. Pavle addressed the impact on electricity demand in "Nulear Plants' Anticipated Costs and Their Impacts on Future Electric Rates," Public Utilities Fortnightly, March 21, 1985, pp. 35-40.

[6] The case for a hiatus in new orders is argued in A. Kaufman and K. K. Nelson, "Do We Really Need All Those Electric Power Plants?", and "An Assessment of the Need for New Electric Capacity," Congressional Research Service, August 1982 and August 1983. For a different view, see T. W. Keelin and E. N. Oatman, "Generating Capacity in U. S. Electric Utilities: How Much is Needed?", Public Utilities Fortnightly, December 23, 1983, pp. 29-37.

The wisdom of this low growth planning strategy has been challenged by those who anticipate a rebound in the demand for electricity. Most notably, Siegel and Sillin have argued consistently that electric utilities are underforecasting demand and, thereby, slipping into strategic errors in system capacity planning.[7] Predicting that the 1980s will be a "mirror image" of the 1970s, with lower real electricity prices and higher economic growth, Siegel and Sillin make the case that electricity demand growth could soon outstrip generating capacity.

The argument for higher electricity growth in the coming decade enjoys the unusual support of recent evidence and successful prediction. Siegel and Sillin have consistently predicted growth rates of 4 - 5%, and the actual growth over the first two years of their horizon was 4.5%. In 1984, for the first time in a decade, load growth exceeded the NERC summary forecast. As shown in Figure 1, we may have pierced the NERC fan. If the high growth forecasters are right, future demand could grow more rapidly than anticipated by the conventional wisdom. And economic capacity planning may be overtaken by events in the need to meet load growth.

Despite the most recent evidence, the debate is far from settled. The long-run analyses of electricity demand address underlying trends but necessarily acknowledge the possibility of short-run deviations from the trend. More to the confusion of planners, the proponents of both high and low forecasts tend to appeal to the same evidence in developing their conflicting judgments. For instance, everyone recognizes the importance of conservation, but there are disagreements about the speed of adjustment or the extent of responses to change in electricity prices. Nearly every study bows to the impact of electricity substitutes and the effects of changes in oil and gas prices, but there is less consensus on whether lower oil and gas prices decrease electricity demand (through substitution) or increase electricity demand (through lower electricity costs).[8] Energy planners recognize the importance of economic growth, but most would like to separate this input and isolate economic uncertainty from the narrower analysis of electricity markets.

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[7] See J. R. Siegel and J. O. Sillin, "Electric Load Growth: Are Utilities Underforecasting?", *Electric Perspectives*, Spring 1983, pp. 3-15; "Changes in the Real Price of Electricity: Implications for Higher Load Growth", *Public Utilities Fortnightly*, September 15, 1983, pp. 32-42; "Rethinking Utility Strategy under Conditions of High Growth", *Public Utilities Fortnightly*, September 13, 1984, pp. 19-26; "Reply", *Public Utilities Fortnightly*, January 10, 1985, pp. 42-43. Siegel and Sillin are not alone in seeing higher electricity growth, for example, see G. L. Spangler and V. P. Wright, "Another Look at Growth in Demand For Electricity," *Public Utilities Fortnightly*, April 26, 1984.

The result of the turmoil is a wide range of growth predictions. For example, the Edison Electric Institute[9] compiled a range of projections as shown in Table 1. Given these divergent results, based on essentially the same data, we are led to a search for consistency in the underlying analyses. Nearly all of the studies weave a complicated tapestry that draws on the historical record but, of necessity, cannot follow directly from empirical estimation with the available data. We look for a framework that will allow us to consider the alternative patterns, provide a complete description of the link between energy and economy, and permit a straightforward estimation of the long parameters from the historical record.

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[8] For example, Siegel and Sillin, September 1984, cite "stable fuel" prices leading to lower electricity prices (p.19), and "the much greater run-up in oil and gas prices...offsetting any reduced electric demand due to 'own' price effects" (pp.19-20) but recognize that "electric prices are quite sensitive to fuel price changes." (p.21). Each of these assertions is correct in context, but the overall analysis does not provide an explicit mechanism for balancing the competing effects on energy and electricity demand.

[9] Edison Electric Institute, Topics in Electricity and the Economy, Volume II, No.1 Spring, 1985, p.3.

Table 1

Average Annual Growth Rates Selected Indicators

	Real GNP	Avg.Imp. Oil Pr.	Primary Energy	End Use	Elec.	Peak Demand	Elec/GNP Ratio
SIEGEL (1983-2000)	3.5	n/a	n/a	n/a	4.5	n/a	1.29
AEO (1983-1995)	2.9	4.6	1.7	1.2	3.3	n/a	1.14
DRI (1983-2000)	2.9	1.9	1.6	1.2	3.1	2.4	1.07
DOE (1982-2000)	2.8	3.0	1.3	0.9	2.8	n/a	1.00
EL. WORLD (1983-2000)	2.9	n/a	n/a	n/a	2.8	2.9	0.97
COM (1983-2000	2.7	n/a	1.1	0.7	2.5	n/a	0.93
NCA (1982-1995)	2.5	1.8	1.4	1.2	2.3	n/a	0.92
WHARTON (1983-1994)	3.3	0.4	1.9	n/a	3.0	n/a	0.91
GRI (1983-2000)	2.8	1.8	1.6	1.3	2.4	n/a	0.86
CON (1982-2000)	2.8	n/a	1.1	0.8	2.1	n/a	0.75
SANT (1980-2000)	2.6	2.3	0.7	0.5	1.5	n/a	0.58
AUD (1980-2000)	2.5	4.7	-0.4	-0.3	-0.8	n/a	-0.32
NERC (1984-1993)	n/a	n/a	n/a	n/a	2.7	2.5	n/a
BANK (1982-2000)	n/a	n/a	n/a	n/a	2.9	2.5	n/a

Legend for table in footnote.[10]

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[10] Notes for Table 1:

AUD:	National Audubon Society, The Audubon Energy Plan 1984, July, 1984. (Conventional Baseline Scenario)
AEO:	U.S.Energy Information Administration (EIA), 1983 Annual Energy Outlook, May 1984.
BANK:	Chemical Bank, U.S.Electric Utility Industry Outlook to the Year 2000. February, 1984.
CON:	Conoco, Inc., World Energy Outlook Through 2000, April, 1984.
COM:	Joseph F. Gustaferro, U.S. Dept. of Commerce, U.S. Energy for the Rest of the Century. July, 1984.
DOE:	U.S. Dept. of Energy (DOE) Energy Projections to the Year 2010 (NEPP IV), October, 1983.
DRI:	Data Resources Inc. Energy Review, Autumn 1984.
EL.WORLD:	Electrical World, "35th Annual Electrical Utility Forecast," September 1984.
GRI:	Gas Research Institute, "1984 GRI Baseline Projection of U.S.Energy Supply and Demand 1983-2000," October 1984.
NCA:	National Coal Association, Coal Markets in the Future, March 1984.
NERC:	North American Electric Reliability Council, Electric Power Supply and Demand 1984-1993. Princeton, New Jersey, 1984.
SANT:	Roger W. Sant et al, Creating Abundance: America's Least Cost Energy Strategy, 1984 (Business As Usual Scenario)
SIEGEL:	John R. Siegel & John Ol Sillin, "Rethinking Utility

In the search for a consistent but simple story, Peck and Weyant summarized many analyses and developed a stylized model that captures the basic economic factors with the gradual adjustment toward long-run trends.[11] Designed for insight as much as forecasting, the Peck and Weyant model illustrates the potential for major shifts in the energy mix. Similarly, in a sequence of analysis starting in 1979, we developed an aggregate model that preserves the essential structure of the underlying long-run economics but is simple enough to permit empirical estimation of the parameters. By focusing on this aggregate model, we guarantee consistency in the analysis of the separate, often conflicting forces affecting energy and electricity demand.[12]

Strategy under Conditions of High Growth," Public Utilities Fortnightly. September 13, 1984.

WHARTON: Wharton Econometric Forecasting Associates. Long-Term Forecast September 1984.

[11] S.C. Peck and J.P.Weyant, "Electricity Growth in the Future," The Energy Journal, Volume 6, No. 1, January 1985, pp.423-44. The model is "stylized" in the sense that the parameters were developed from many sources rather than being estimated directly from the historical data.

[12] See Energy: The Next Twenty Years, Ballinger Publishing Co., Cambridge, MA, 1979, chapter 2, for an early version of the model. A more recent update appears in W. Hogan, "Patterns of Energy Use," EEPC Discussion Paper, Harvard University, 1984.

8

STRUCTURE OF ENERGY DEMAND

We sought the simplest accounting of the changes in the patterns of energy use that might explain the past and guide our expectations for the future. The recent energy history was marked by the rapid changes in energy prices. Figure 2 records the upheaval in energy prices that followed the oil shock of 1973 and 1979. The first result of these higher prices was an immediate decline in the previously steady growth of energy demand. As shown in Figure 3, the abrupt change in the growth of demand cut across all the major sectors of the economy.

A review of the data reveals that the patterns of energy use have been dominated by three principal factors: (1) inter-fuel substitution, (2) energy conservation, and (3) economic growth. Historically these three factors have had important but distinct effects on the growth in electricity demand. A mechanical extrapolation of recent experience would ignore the countervailing effects of these factors. We separate these three factors to provide a consistent description that integrates the basic data and the theory of long-run economic assumptions.

The first effect, inter-fuel substitution, recognizes the major changes in the mix of fuels used to provide energy services. Without question, the most significant result of fuel substitution has been the continued electrification of the economy over a span of decades. A source of this change in the role of electricity was the steady reduction in the relative price of electricity. Figure 4 reveals that relative electricity prices fell even after 1970, during the time when the absolute price of electricity was on the rise. The electricity share of total energy demand increased from 6.1 percent of final demand in 1960 to 8.7 percent in 1970.

Figure 2

CONSUMERS FACED HIGHER PRICES
IN ALL MAJOR ENERGY CATEGORIES

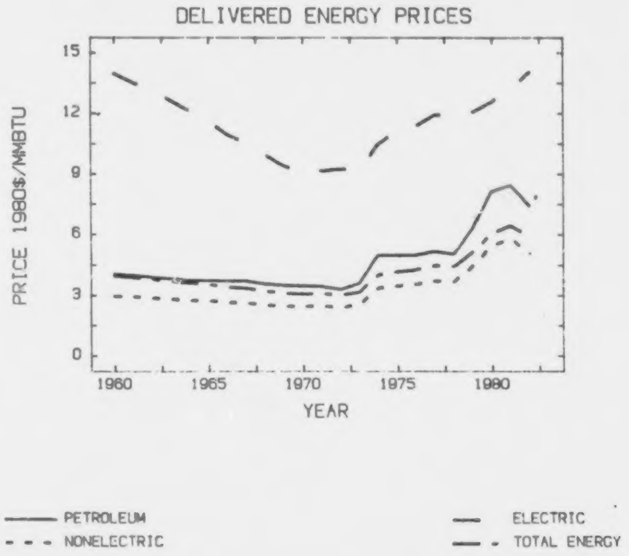


Figure 3

HIGHER PRICES DAMPENED ENERGY DEMAND

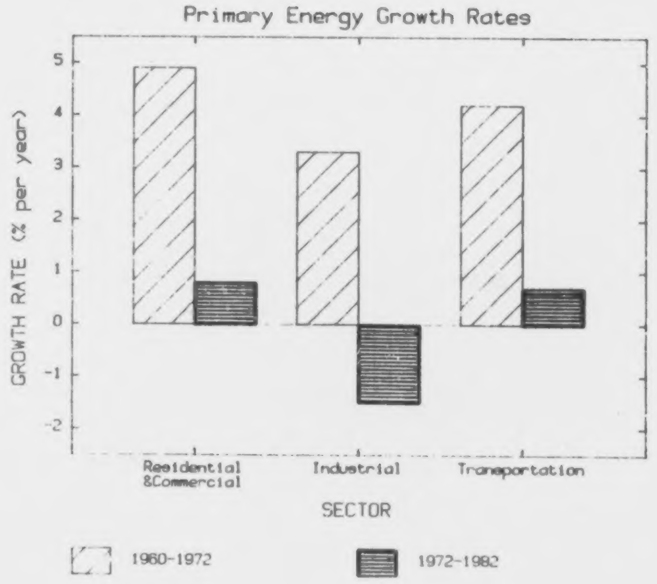
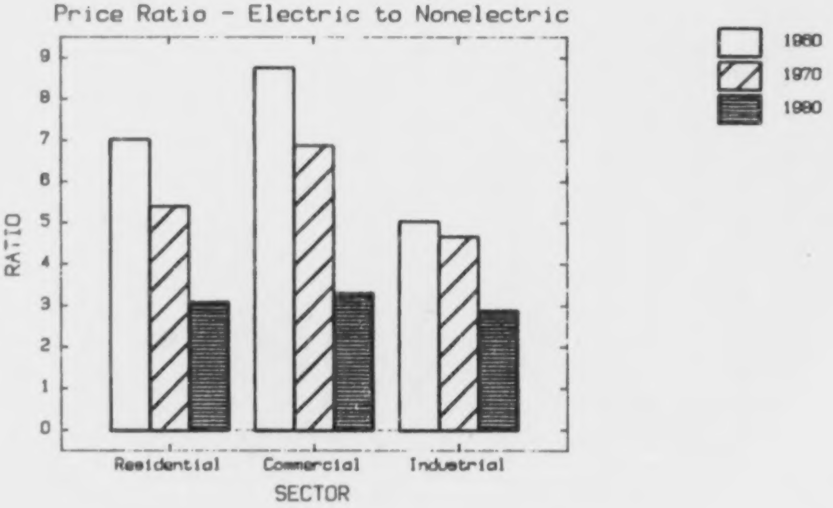


Figure 4

FALLING ELECTRICITY PRICE EXPLAINS ELECTRIC FOR NONELECTRIC SUBSTITUTION



This is a familiar result. But what is less appreciated is the continuation of that trend even during the period of increasing energy prices. Although the growth in demand for all energy products fell after 1970, the electricity share of total demand continued to grow, increasing to 12.7 percent by 1982. As relative prices changed, consumers substituted electricity for other fuels.

If the price of electricity rises more rapidly than the price of other fuels, in the future we would expect the reverse substitution to occur. Conversely, if electricity prices fall relative to other energy products, then the trend towards greater electricity use should continue. But in any event, it is necessary to separate a consumer's decision between using natural gas or oil and the possibility of using electricity for many of the same ultimate purposes.

Energy conservation has been an equally important part of the energy story. With sudden increases in energy prices, all consumers recognized the opportunity to improve energy efficiency in homes and factories. For instance, given the great differences in energy intensity across countries, we recognized the potential for significant reductions in the use of energy in the United States. This potential for long-run efficiency in energy use per unit of activity is among the important avenues for improving the productivity of our economy. The price increases since 1972 have created the potential for a total reduction in energy use per unit of activity of 40 to 50 percent. This conservation factor is a second and equally important feature of our model.

The third factor is the growth in general activity as represented by the growth in the economy. Even if we succeed in substituting other fuels for electricity, or our conservation efforts result in a great improvement in energy efficiency, the growth in total economic activity will eventually increase the aggregate demand for energy and electricity. Ultimately the increase in economic activity must play a major role in any projection of total energy demand.

These three factors, interfuel substitution, energy conservation, and economic growth, interact in different ways over time. Economic growth will have an incremental and immediate impact. But energy conservation and interfuel substitution may take place with delayed effect. In large part, the fuel and energy efficiency of factories and homes are determined by the nature and age of their capital stock. Hence a change in fuel and energy efficiencies will unfold slowly as we build new homes or refurbish old factories. Given sharp changes in relative prices, such as we have experienced in the last decade, improvements in energy efficiency changes will develop slowly over a number of years.

ENERGY TRENDS

Hence, we expect a pattern such as we have seen in total energy demand: with higher prices, energy conservation begins to reduce the total demand for energy. At the same time, economic growth tends to increase the total demand and, for a number of years, the net effect is roughly balanced. Energy and electricity growth remain relatively flat as the two countervailing forces continue to work against each other. But eventually the conservation adjustment will be complete when the capital stock is replaced, and only the force of economic growth will remain. Unless we see further dramatic changes in prices, therefore, the growth of energy demand should return to follow growth in the economy. If the relative prices of the products are changing, then the substitution among alternative energy products may cause electricity demand to grow more rapidly and oil demand to grow less rapidly than economic activity. The difficulty centers on separating these transitional effects from the long-run trends. The separation of the interplay among these factors is the purpose of our model.

Using historic data, 1960-1982, for the United States, we formulated a conventional long-run model to relate the demand for nonelectric energy, electric energy, and other activity in the economy.[13] We combined this long-run model with a description of the adjustment process to reflect a gradual transition in the capital stock. This produced a dynamic model that would recognize and follow the complicated overlay of changes in the historical record due to the sequence of significant price shocks. With such a system we estimated the parameters for both the short and long-run response to changing prices and economic activity.

By conventional econometric standards, the quality of the resulting estimates is excellent.[14] The model equations all have very high "R-squared" values (explaining over 99 percent of the variance in the historical data). The "t-statistics" on the individual elasticities pass the usual tests of significance. Furthermore, the measured long-run responses to prices and income changes compare favorably with other studies with more detailed econometric models. In addition, the parameters reflect a very large long-run potential for both inter-fuel substitution and energy conservation. Hence, the model includes a great deal of conservation potential and opportunities to substitute other fuels for electricity.

One of the most suggestive summaries of the quality of the fit of historical data is found not in the technical statistics but in the simple graphical presentation shown in Figure 5. Here we see that the model tracks closely the actual performance of electric and nonelectric demand over the turbulent period between 1960 and 1982. The equations capture turning points; the model follows the dramatic price shocks and requires no special "fixes" to deal with troublesome years. Moreover, we can apply the model to reflect the declining relative price of electricity and reveal the large degree of interfuel substitution as the energy mix moved away from nonelectric sources of energy and toward electricity. During the time when real prices were falling, electricity demand grew faster than the economy. During the years when prices were rising, absolute demand for electricity was lower but the electricity share continued to increase.

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[13] Ibid.

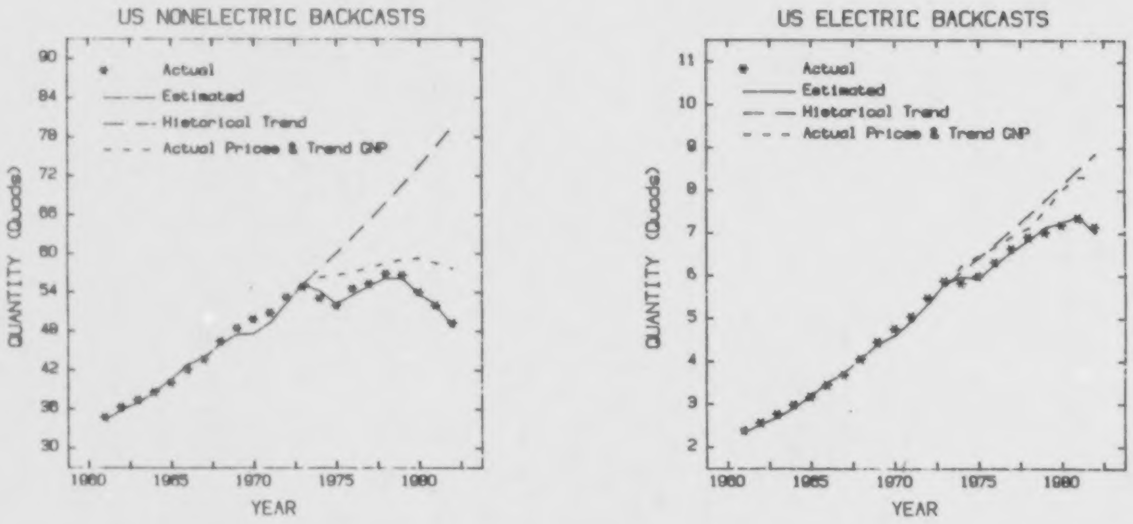
[14] Ibid.

As shown in Figure 5, we can separate the substitution effects of changing prices from the growth effects of cycles in GNP. The backcasts over the historical period, but with constant prices and trend GNP, generate the trend energy demand scenario that would have developed without the shocks of the past decade. When we apply the actual prices, but retain the trend GNP, we create a case that isolates the price effects. For nonelectric energy, the higher prices had a great impact. Both the effect of improved efficiency and the tendency to substitute away from nonelectric energy led to reduced demand growth. But for electric energy these effects where compensating; the improved efficiency was almost balanced by the increased share of electricity in the energy mix. For both forms of energy, the remaining demand reduction is explained by the changes in economic growth.

The model has been robust in the face of a number of alternative implementations. Changes in the period of estimation, to eliminate the most recent years, decrease the confidence but not the point estimates of the parameters. Furthermore, we have applied the model successfully to the study

Figure 5

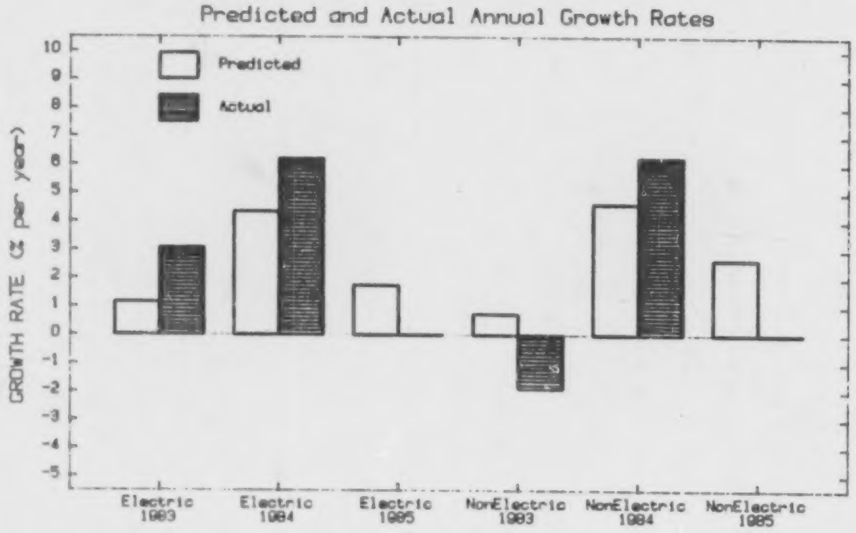
WE CAN EXPLAIN THE AGGREGATE ENERGY DATA



Note: Actual values are Translog indexes of electric and nonelectric demand. Estimated values and backcasts under alternative assumptions taken from energy demand model estimated over 1960-1982.

Figure 6

ENERGY DEMAND MODEL PREDICTIONS FELL BELOW RECENT TRENDS



Predicted and Actual Annual Growth Rates

Note: Growth rates are for Translog indexes of electric and nonelectric demand. Predictions for 1983-1984 based on estimated values of actual energy prices and GNP. Prediction for 1985 assumes 4% GNP growth and 1984 trends in prices. Demand model estimated on data through 1982. Actual data for energy consumption and prices estimated from October 1984 MER.

of energy and electricity demand for regions as different as the State of New Hampshire, the Pennsylvania-New Jersey-Maryland power pool, and a midwestern utility. In each case, the basic parameters were consistent and the pattern of energy demand adjustments suggested a slow adaptation to large long-run shifts in the mix between electric and nonelectric energy.

An alternative test of the simple model compares the predictions outside the period covered by the data base with the actual events in recent energy markets. We estimated the model with data for the period 1960-1982, to capture both a long period of adjustment and the impacts of two major energy price shocks. Unfortunately, we do not yet have a completely consistent data base for the years 1983-1984 -- the individual fuel consumption and price statistics had not yet been published by early 1985. However, we can use other sources to estimate the changes in the aggregate levels of energy consumption, changes in prices and the growth in economic activity.[15] With these preliminary estimates, we can use the observed values of GNP and prices to compare the predicted and actual growth in the electric and nonelectric energy categories.

The comparison of the predicted and actual growth rates for 1983-1984, plus the base case projections for 1985, appear in Figure 6. Here we see a mixed performance for electric and nonelectric growth. In both years, the predicted growth rate for electricity fell below the actual growth rate. This covered a period of remarkable recovery in the economy, approximately 7% growth in 1984, with electricity demand growing slightly less rapidly than the GNP. Perhaps the deviation between predicted and actual can be explained by a bias in growth sectors during the recovery from recession.[16] For nonelectric energy demand, the forecast errors balance out over the two years, with the average of the two-year forecast showing almost no error. From this limited validation test, therefore, we might conclude that the model captures the basic structure of the dynamics of energy demand growth but may be biased to underestimate the full growth potential in electricity demand.

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[15] Economic Report of the President, January 1985; DOE Monthly Energy Review, January 1985.

[16] For a discussion of the increased sensitivity of electricity

We can review also the 1983-1984 experience compared with the forecasts summarized in Table 1. Recognizing the pitfalls in contrasting any short-run results with long-run trends, we know that there is no straightforward test of any of the predictions. Perhaps the electricity-GNP ratio provides the best shorthand correction for the differences in assumptions. The average growth in electricity demand over 1983-1984 was 4.5%, just as predicted by Siegel and Sillin. But the 5.1% growth in GNP deserves most of the credit for the spurt in demand. The resulting 0.89 electricity-GNP ratio falls about in the middle of predictions in Table 1, far from the high of 1.29 of Siegel and Sillen or the low of -0.32 from the National Audubon Society.

ENERGY DEMAND FORECASTS

We have presented a simple analysis of the aggregate data which explains the behavior of energy demand without appeal to complicated changes in the structure of the economy, fundamental shifts in the laws of supply and demand, or regulatory interventions by government. Other more elaborate theories may also be consistent with the data, but we need not look further

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demand to movements in the business cycle, see M. L. Hays and B. G. Humphreys, "Electricity Sales and the Business Cycle", *Electric Perspectives*, Summer 1984, pp. 28-39.

for an explanation of the changing patterns of energy demand to the effects of relative prices and the growth in the economy. Naturally, our interest in the analysis of energy demand extends beyond the examination of the past to consider the implications of the analysis for the future trends in energy demand. We turn from review to forecast.

Any projection with this model requires assumptions or estimates for electricity price, nonelectric energy price, and total economic activity. For these inputs we begin with the forecast published by the U.S. Department of Energy.[17] We applied the DOE projections but treated separately the changes in oil prices and the trends in other factors (e.g., capital costs) that contribute to electric and nonelectric prices. In this way we could represent both the uncertainty in key inputs and the principal correlation (through oil prices) that will affect all energy costs. For our base line projection, we adopted the DOE input assumptions to obtain a projection through the year 2020.

The forecast and the effects on electricity demand appear in Figure 7. Faced with the projected electricity prices for the next several years, the effects of energy conservation and inter-fuel substitution greatly moderate the growth in electricity demand. Despite increases in the level of economic activity, we expect electricity demand to grow at a rate below the rate of economic growth until the early 1990s. Later, with few new plants entering the rate base after the long hiatus in construction, real electricity prices cease rising and actually start to fall. At the same time, higher oil prices, according to the Department of Energy's forecasts, will produce market reactions that will increase the price of all energy products. Natural gas

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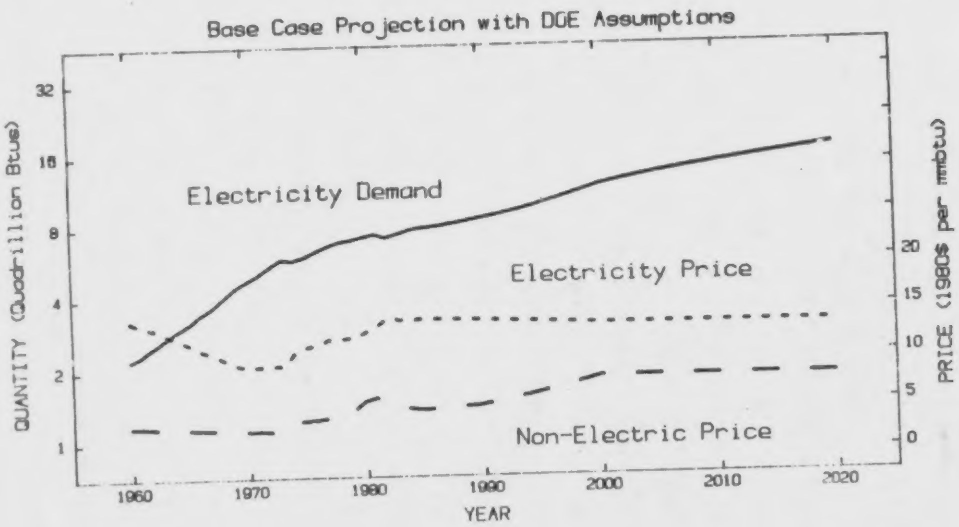
[17] 1984 Annual Energy Outlook, Energy Information Administration, United States Department of Energy, Washington DC, January 1985.

Figure 7

DEMAND WILL ADJUST TO CHANGING ENERGY PRICES



Note: Base Case Projection with Demand Model for central values from DOE 1984 Annual Energy Outlook for GNP and energy prices.

prices will rise, and the cost of generating electricity will increase. On balance, the increases in nonelectric prices, for which oil plays a major role, will be greater than the increases in the price of electricity. Hence the relative price of electricity will fall if oil prices increase. As the economy continues to grow, the previous pattern reverses. Other things being equal, this reduction in the relative price of electricity will cause a substitution towards electricity. Hence the effects of inter-fuel substitution lead to increases in electricity demand for a number of years. Under these conditions, electricity demand grows more rapidly than the economy. The net result is a two-part pattern of slow electricity growth, as we accumulate the effects of substantial energy conservation, followed by more rapid growth as we exhaust the economically justifiable conservation opportunities but face tightness in other competing energy markets.

The pattern described in the base case projection is quite consistent with our history. The price changes that we expect in the next decade are modest compared to the changes in prices that we have experienced. The residual effect of energy conservation from past price increases is large enough to counteract the effects of economic growth for several years. But the residual effect is dissipating and eventually the forces of economic growth will prevail. The anticipated future changes in electricity prices and nonelectric prices all point to higher eventual electricity demand. However, the price changes are more modest than we have experienced historically so the projected increases in electricity demand, relative to economic growth, are significantly below the levels we experienced during the 1960s.

In short, the forecast is well within the range of variability of the historical database, is consistent with *a priori* arguments about the interaction among the fuels, incorporates a substantial estimate of the effect of energy conservation, and separates the effects of economic growth. Furthermore, the model used to produce these projections is estimated directly from the historical data and fits the record well during a period of much greater price variability than that expected in the current DOE projections. The same model has been applied to regional data with similar results.

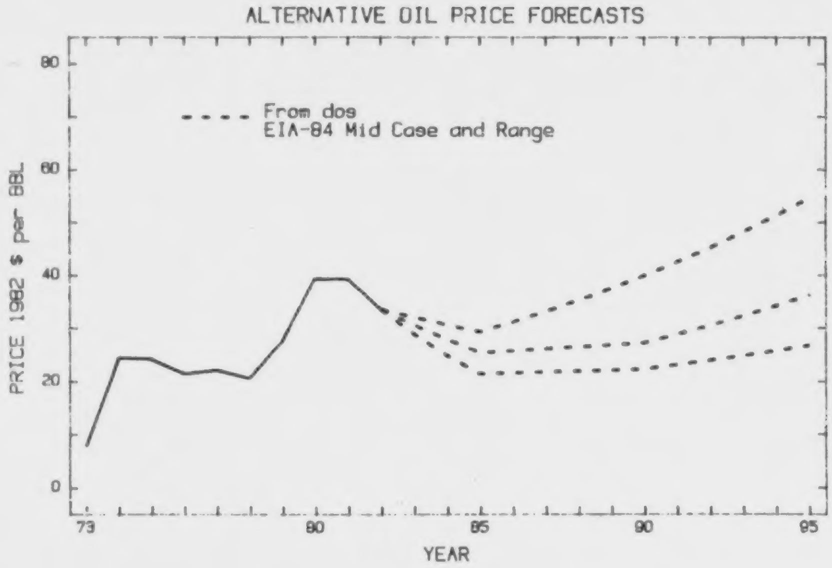
RISK ANALYSIS OF ENERGY DEMAND

The range of variability in the past is suggestive of the range of variability in the future. Therefore, it is essential to recognize the degree of uncertainty induced by events which will affect the growth on nonelectric and electric prices and economic growth. To capture these effects, we can focus on the differences in the price forecasts that might unfold compared to those included in the base case. For example, in Figure 8 we recognize that the DOE has applied a range of assumptions for the critical oil price input assumptions, including relatively stable prices on the low end to a high end return to a tight oil market in the 1990s. We would like to examine this range of uncertainty in order to consider the effects on the projections for energy demand growth.

One approach to the investigation of the uncertainty would be to prepare an alternative demand forecast for each oil price case. However, we acknowledge that oil prices alone will not control the uncertainty in the demand forecast. Economic growth, for instance, will have an even greater impact on the level of energy demand. As we have seen in Table 1, the variability of input assumptions between forecasts is as great as the variability of electricity demand projections. In effect, we could create a plausible scenario for almost any feasible combination of assumptions. The

Figure 8

DOE-EIA PROJECTS A RANGE OF OIL PRICES



Note: The Energy Information Administration (EIA) forecasts taken from the 1984 Annual Energy Outlook, DOE, January 1985.

task, therefore, is to step beyond the scenario analysis of a few cases and look across a broader range of alternatives.

For our model, we can include uncertainties in all the major inputs. In Figure 9. we summarize these uncertainties in a probability tree. Here, each node represents a key input uncertainty over an appropriate time period for GNP growth, non-oil costs and oil prices. The branches record the range of assumed values, with the middle branch at each node set to reproduce the DOE base case. This risk analysis presents us with far too many combinations to consider every case as a separate scenario.[18] However, by assigning probabilities to each branch we can determine the probability of each scenario of input assumptions and calculate the associated probability of the output distribution of energy demand growth rates. Any individual path through the tree will have a low probability of occurring, but we can calculate the total probability for the range of possible energy demand growth rates.

The results of this risk analysis appear in Figure 10 where we present the cumulative probability distributions for the several key elements of interest. The solid lines record the probability distribution for the decline in the relative price of electricity and the growth in the GNP. We recognize that with further tightness in the oil market, and no new construction beyond that already planned in the electricity sector, we could enter a period with

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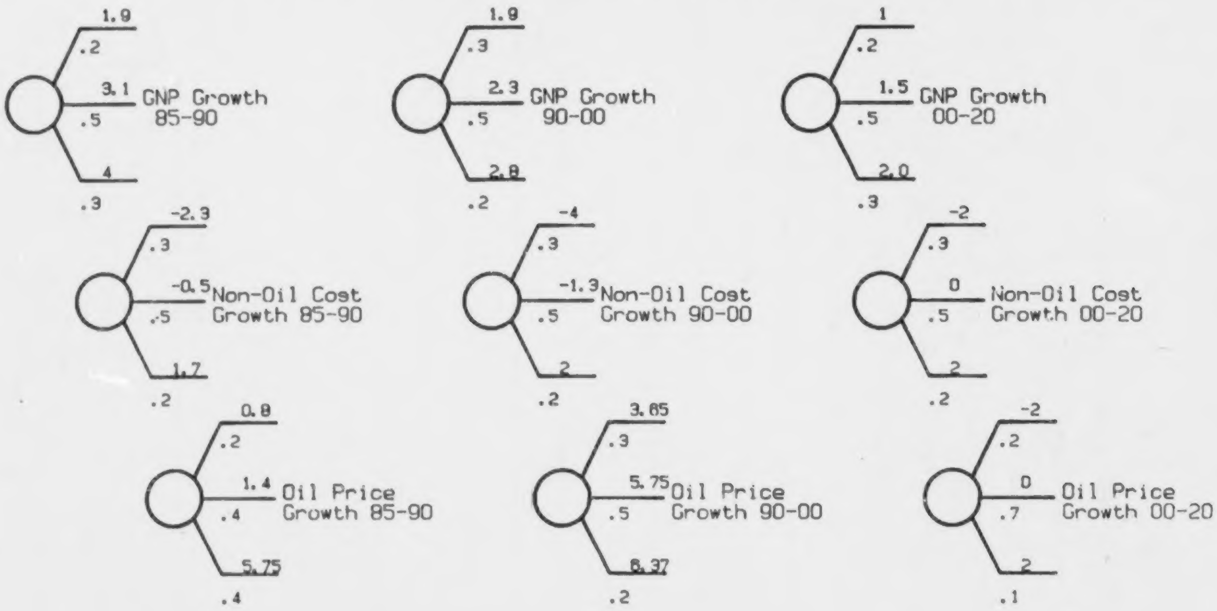
[18] Risk analysis, the examination of the range and the probability of occurrence across a set of outputs, is often proposed but less frequently practiced as an important component of analysis for decision making. See D. Hertz and H. Thomas, Practical Risk Analysis, John Wiley and Sons Inc., New York, 1984, for an explanation of the pragmatic strengths of risk analysis techniques. For an interesting application in the context of utility planning, see K. C. McKinley, "Fuel Planning in Uncertain Times", Public Utilities Fortnightly, November 24, 1983, pp. 32-36. Notably, Peck and Weyant, "Electricity Growth," apply a similar risk analysis to their forecasts of electricity demand.

Figure 9

RISK ANALYSIS EXTENDS THE
ENERGY DEMAND GROWTH ASSUMPTIONS


1.9
.2
3.1
GNP Growth 85-90
.5
4
.3
1.9
.3
2.3
GNP Growth 90-00
.5
2.8
.2
1
.2
1.5
GNP Growth 00-20
.5
2.0
.3
-2.3
.3
-0.5
Non-Oil Cost Growth 85-90
.5
1.7
.2
-4
.3
-1.3
Non-Oil Cost Growth 90-00
.5
2
.2
-2
.3
0
Non-Oil Cost Growth 00-20
.5
2
.2
0.8
.2
1.4
Oil Price Growth 85-90
.4
5.75
.4
3.65
.3
5.75
Oil Price Growth 90-00
.5
8.37
.2
-2
.2
0
Oil Price Growth 00-20
.7
2
.1

Note: Non-Oil Electricity Cost, Oil Prices and GNP uncertainties for 1985-1995 set relative to assumptions adopted from the DOE 1984 Annual Energy Outlook.

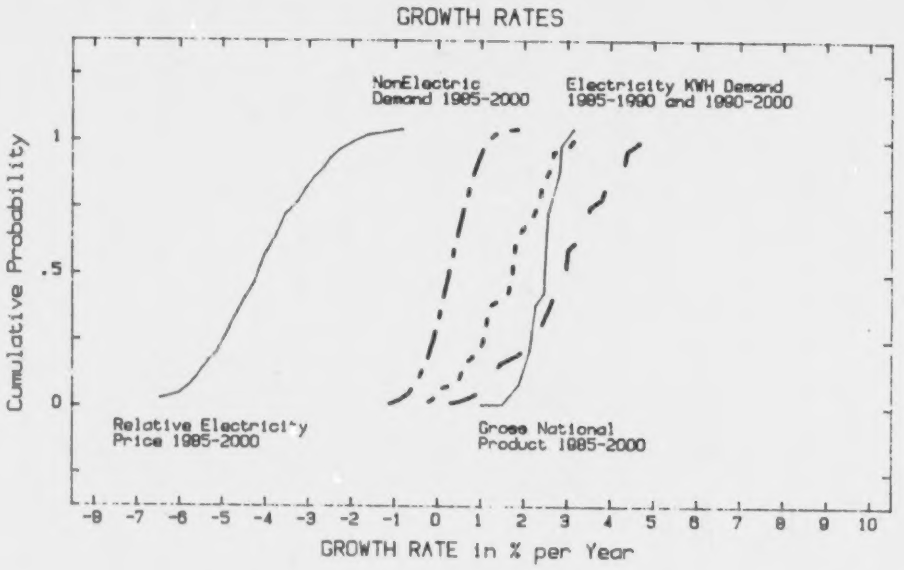
rising non-electric prices and relatively falling electricity prices. There is great uncertainty about the magnitude of this decline in the relative price of electricity, as reflected by the wide range for the cumulative probability distribution. But this change in relative prices would lead to a realm of even greater substitution away from expensive non-electric energy and towards the use of electricity.

The dashed lines in Figure 10 record the probability distributions for the growth rates in electric and nonelectric energy demand. The distribution for nonelectric energy demand, over the period from 1985-2000, spans a slight decrease in aggregate demand to a slight increase. But in any event the range implies that nonelectric energy demand will grow more slowly than the economy. By contrast, electricity growth over this same period could outpace the economy. The average growth rate in electricity demand is 2.59%, based in part on an average GNP growth of 2.5%, for an electricity-GNP ratio of 1.03. Compared again to Table 1, our result falls toward the higher end, but far from the extreme. However, the time pattern of growth suggests that the next few years could be a poor indicator of the longer-run trend. Figure 10 separates the electricity projection into two periods. For the period 1985-1990, the continued effect of conservation in response to previous price increases dampens electricity demand growth relative to the economy. But during the subsequent decade, the incentives of the projected changes in relative prices take over and electricity demand growth jumps ahead of the anticipated trend in the economy. Furthermore, the uncertainty in the electricity demand projections increases as we look further ahead, and the growth in electricity demand could span a wide range.

This wide range of possible growth rates emphasizes the difficulty of relying on a single projection. Each projection included in the risk analysis

Figure 10

RISK ANALYSIS DISPLAYS THE UNCERTAINTY IN NATIONAL ENERGY DEMAND GROWTH FORECASTS



Note: Energy price and GNP uncertainties set relative to DOE 1984 Annual Energy Outlook. Demand projections developed with energy demand model.

reflects a possible future. The growth rates and price assumptions are internally consistent and reflect the patterns of energy use in the historical data. Hence it is possible to produce a scenario which envisions very low electricity growth or a scenario which envisions very high electricity growth. The issue we must address, therefore, is the probability of each of these scenarios. Given the risks, we would then turn to the practical matter of examining the decisions that will be affected by the uncertainty over energy demand growth. We have attempted to provide the beginnings for this perspective in our risk analysis of electricity growth rates. The risk analysis summarizes the probability of each of the consistent scenarios examined over this horizon. We have found this risk perspective useful for examining the national data and the situations for individual utilities.

CONCLUSION

Given a decade of dramatic changes in energy prices and energy efficiencies, it is easy to conclude that the short-run changes are permanent. However, we have shown that a straightforward explanation of the historical data can provide a consistent set of projections that are sensitive to changing conditions in the future. Our model merges the short-run and long-run analyses and displays the connection between the market turmoil and the changing patterns of energy use. The system is not in equilibrium today. We cannot look at the aggregate growth rates of the last few years and mechanically extrapolate into the future; as the capital stock adapts fully to the increase in energy prices, more rapid electric load growth can be expected. However, the change in relative price and the increases in electricity demand will occur at the margin for new capital stock. Hence the full effect of changes in prices will be spread out over several years. And the time path of adjustment may lead to slow electricity growth followed by accelerated demand increases, which may prevent the most challenging pattern for decision makers. With long lead times for capital investments, the uncertainty of possible electricity demand growth points to risk analysis as the next step in addressing demand uncertainty.

Senator EVANS. Thank you very much, Dr. Hogan.

We'll go through the entire panel before we get to questions.

Dr. French.

STATEMENT OF DR. MARK W. FRENCH, MANAGER, ENERGY ANALYSIS, WHARTON ECONOMETRICS FORECASTING ASSOCIATES

Dr. FRENCH. Mr. Chairman, my name's Mark French. I'm manager of energy analysis at Wharton Econometrics.

Wharton has used computerized models of the U.S. economy and of its component regions to project growth in demand for electricity over the coming 10 years. We have compared our projections with those of other forecasters and of the utilities themselves. These projections are similar in aggregate to those of the utility industry.

Wharton expects that overall U.S. electricity demand will increase by a bit under 3 percent per year over the next 10 years. This average growth rate is pretty similar to Wharton's projections for the annual increase in gross national product.

Changing regional trends in economic growth will have a substantial impact on regional electricity demand over the coming decade. Wharton expects that regions which suffered relatively weaker growth in the last decade, the Middle Atlantic and New York among them, will experience relatively rapid growth in the coming decade, relative to other regions.

Industries concentrated in the Frost Belt are expected to expand more rapidly in the coming decade, notably manufacturing durable goods output. A number of industries focused in the Sun Belt, including oil, are likely to expand more slowly in the coming decade.

Many utilities over the past decade have been burned by ambitious plans for capacity expansion based on demand for electricity that never materialized, given the shifts in regional economic structure. Based on these experiences of delays and cancellations, many utilities along the east coast appear to be underestimating future demand growth, while two of the census regions in the central United States appear to be overestimating demand growth in light of Wharton's expectations regarding changing industrial mix regionally.

In the table that I've submitted in my testimony, Wharton summarizes its projections for regional electricity demand growth and compares these projections with those of the U.S. electric utilities as summarized by the North American Electric Reliability Council.

Potential difficulties for utilities appear likely when average growth of demand over a long period differs from planned load growth. Wharton's projections are remarkably close to NERC's for the United States and indeed for most regions, suggesting that on a national basis utilities have planned to generate or purchase sufficient power to meet demand requirements.

On a regional basis, however, several potential problems appear in terms of demand growth expectations. Wharton expects substantially faster growth in electricity demand in the mid-Atlantic and south Atlantic than do the utilities in those regions. In both these regions, utilities expect to meet part of the growth in demand with renewed growth in oil-fired generation from 1987 onward.

If demand growth is indeed significantly faster than these utilities expect, they are likely to need to make use of even greater amounts of higher cost oil-fired generation. Alternatively, these utilities will have to purchaser more power from regions with excess generating capacity. In the case of New York State, this would imply increase electricity imports from Canada beyond currently planned levels.

Wharton expects, however, that the need for greater generating capacity in the 1990's will be clear in time to increase capacity or to contract for the extra power. Lead time on oil-fired projects, for example, or on putting up existing—putting back in operation existing oil-fired capacity is substantially less than for coal-fired plants. Thus, Wharton does not expect significant interruption or rolling brownouts in the 1990's; rather, the potential for higher than necessary prices in certain regions in the 1990's for electricity.

Electric utilities do have an incentive to pursue a strategy of capital minimization. Many utility executives once proclaimed the need for ambitious construction programs to meet anticipated demand and to replace more expensive oil-fired units. These same utilities have been delaying or canceling their construction projects, at significant cost to consumers and stockholders.

Utilities are now much more willing to rely on purchased power and third party financing schemes than to undertake new construction projects. There are a number of factors contributing to the utilities' incentive to minimize their investment.

The rate suppression issue, as has been raised in the set of questions we received, is only one of these issues. Higher interest rates over the past several years in real terms have increased the cost of borrowing for new investment, and these real interest rates are expected to remain high by historical standards for several more years, given prospective U.S. fiscal and monetary policy.

Another aspect of the capital minimization policies that we've seen has to do with the investments in new capacity which occurred in the 1970's in anticipation of load growth which never materialized. Capacity utilization rates in the utility industry have fallen from 52 percent in 1972 to 40 or 41 percent in 1983–84.

Given current reserve margins for most utilities, there is not immediate pressure to add capacity to increase reliability of service. I might add that much of the current comfortable national reserve margin is higher cost oil-fired generation.

Investments in base plant current underway are not sufficient in some regions to meet projected base load demand in the early 1990's. Yet the lead time for a new coal plant can be 8 years or more, and to avoid costly use of oil-fired capacity a few new investments in coal-fired plants should be in the planning stages right now.

New base load investments are not planned for the near future, and one major reason is the phenomenon that Peter Navarro of Harvard calls rate suppression. Rate suppression occurs when PUC's fail to set electricity prices that keep pace with energy and capital costs, causing real earnings to fall below the industry's cost of capital. When earnings fall below the market rate of return, every dollar that a utility invests in fixed capital loses money compared with the alternative option of bond purchases or retirement of debt.

A related regulatory problem to rate suppression is the used and useful criterion used by PUC's to determine whether a new plant can be included in the rate base. A number of PUC's have not allowed construction costs of new plants in whole or in part to enter the rate base, on the ground that they do not increase reliability by the used and useful criterion.

In some cases, these plants were economically desirable nonetheless in reducing the average cost per kilowatt-hour of electricity generation. Unfavorable decisions in many such cases have tended to form an adversarial atmosphere between utilities and PUC's. Some utilities feel that their stockholders are being forced to bear all the risks of construction decisions, a view consistent with the "sufficient prudence 'criteria sometimes mentioned in rate cases.

Rate suppression and the shifting of the burden of risk, in addition to high real interest rates economywide, have together served to increase the difficulty for utilities of raising capital to finance new generating units. The rate suppression decisions made by a number of State utility commissions are an important element behind the reluctance on the part of public utilities to invest in new plant. The utility industry has in fact given an answer to economists concerning the investment strategy that will result in adequate returns.

That strategy is an underinvestment in new central station generating plant, underinvestment in the conversion of less efficient units, and underinvestment in conservation costs. The cost of this strategy will be seen in the 1990's, when much of the added capacity will be expensive oil and gas-fired plants.

Thus, if the institutional forces which suppress rates do not moderate, consumers may well face higher rates and the economy may face greater dependence on imported oil. Service interruptions and rolling brownouts can probably be averted with investments in putting on line oil-fired or gas-fired capacity, which has a relatively short lead time.

The responsibility for decisions concerning electric power supply should probably reside with both local PUC's and the utilities. Such joint decisionmaking should probably be accompanied by some risk-sharing between stockholders and ratepayers, but for a joint relationship to work effectively several changes would have to occur.

The adversary relationship between PUC's and utilities would have to be reduced. PUC staffs would have to be expanded, possibly in a regional framework, to facilitate the development of viable supply strategies, with PUC's responding to economic issues as well as political pressures. The used and useful and reliability criteria would have to be modified to consider cost-saving investments and not simply investment to meet load growth.

Federal actions. The main Federal action that would assist the electric utility industry in expanding its base load to meet expected demand would involve reduction of real interest rates. We're talking about the problem of the Federal deficit and the relationship with real interest rates economywide.

If that deficit comes down, there is significant potential for easing of this rate suppression problem and of the cost of borrowing for investment by electric utilities.

Thank you.

[The prepared statement of Dr. French follows:]

WHARTON
ECONOMETRIC
FORECASTING
ASSOCIATES

1110 Vermont Ave. N.W. Suite 700 Washington, D.C. 20005 202/887-8700

July 22, 1985

The Honorable James McClure
U.S. Senate
Washington, D.C. 20510

Dear Senator McClure:

Wharton is pleased to submit the attached written statement which describes our estimate of the likelihood of electric capacity shortages on a regional basis by the early 1990s. We also briefly review the issues of rate suppression and capital minimization. Our analysis of electricity demand was performed using Wharton's Long-Term Model of the U.S. economy and Wharton's Census Region Economic Model. The results of our analysis suggest that current utility investment plans, in conjunction with an imperfect regulatory structure, will give rise to unnecessarily expensive power in some regions. However, actual interruptions or rolling brownouts appear unlikely.

The North American Electric Reliability Council (NERC) has collected projections of growth in electricity demand from U.S. utilities, as well as planned growth in generating capacity. These data are published in NERC's publication 'Electric Power Supply and Demand, 1984-1993'. Wharton has compared its projections for regional electricity demand growth with NERC's summary. Several issues stand out.

- Almost 90 percent of total planned retirements are oil and gas-fired units which are uneconomical given expected prices for these fuels.
- Nonetheless, utility projections imply that U.S. generation from oil-fired units will bottom out in 1987 and then start to increase.
- Two regions which expect renewed growth in oil-fired generation after a trough in 1987 are the Mid-Atlantic and the South Atlantic census regions.
- For both these regions, Wharton expects substantially more rapid growth in electricity demand than do the utilities themselves.
- For these regions, and probably New York as well, Wharton sees potential for significant increases in the real cost of electricity as utilities turn to purchased power or higher-cost combustion generation in the 1990s to meet unexpectedly rapid demand growth.

- Nationwide, however, baseload generating capacity should be adequate to meet demand growth in line with overall economic growth. In fact, Wharton's projections suggest that planned investment will create surplus capacity in the East South Central and West North Central census regions.

- "Rate suppression" is only one of several reasons for utility capital minimization strategies, but dealing with this issue offers the potential to reduce the long-term growth in cost of U.S. electricity.

Sincerely,

Mark French

Mark French
Manager of Energy Analysis

John Del Roccoli

John Del Roccoli
Director of Regional
and Utility Economics

WHARTON
ECONOMETRIC
FORECASTING
ASSOCIATES

SUMMARY HIGHLIGHTS OF THE WHARTON TESTIMONY BEFORE THE COMMITTEE ON ENERGY AND NATURAL RESOURCES

July 22, 1985

U.S. Senate
358 Dirksen Building
Washington, D.C. 20510

Statement of
Mark W. French
Manager of Energy Analysis
Wharton Econometric Forecasting Associates
3624 Science Center
Philadelphia, PA 19104

Wharton has used computerized models of the U.S. economy and of its component regions to project growth in demand for electricity over the coming ten years. We have compared our projections with those of other forecasters and of the utilities themselves. These projections are similar in aggregate to those of the utility industry. Wharton expects that overall U.S. electricity demand will increase by 2.8 percent per annum from 1984 to 1994. This average growth rate is similar to Wharton's projection for the annual increase in gross national product.

Changing regional trends in economic growth will have a substantial impact on electricity demand over the coming decade. Wharton expects that regions which suffered relatively weaker growth in the last decade — the Middle Atlantic and New York among them — will experience relatively rapid growth in the coming decade. Industries concentrated in the Frostbelt are expected to expand more rapidly in the coming decade, notably durable goods output. A number of industries focused in the Sunbelt, including energy, are likely to expand more slowly in the coming decade. The accelerated growth in the Sunbelt has driven up wages relative to the Frostbelt, limiting future employment shifts between these regions.

Many utilities over the past decade have been burned by ambitious plans for capacity expansion, based on demand that never materialized, given the shifts in regional economic structure. Based on these experiences, many utilities along the east coast appear to be underestimating future demand growth, while two of the census regions in the central U.S. appear to be overestimating demand growth, in light of our expectations regarding changing industrial mix. In the following table, Wharton summaries its projections for regional electricty demands growth, and compare these projections with those U.S. electricity utilities, as summaries by the North American Electric Reliability Council. Beginning (the comparison necessarily approximate, since NERC's regional divisions correspond only approximately with Wharton Census-Region splits.)

WHARTON

Table 1
10-YEAR REGIONAL ELECTRICITY DEMAND GROWTH PROJECTIONS

	Wharton	NERC
United States total	2.8%	2.7%
New England	2.9%	2.5%
New York	2.3%	1.4%
West North Central (Mid-Continent Area)	2.1	2.9
East North Central (Mid-America + East Cent.)	2.7	2.3-2.4
Mid-Atlantic	3.0	1.8
South Atlantic	3.4	2.9
East South Central (Tennessee Valley Auth.)	1.9	3.4
Rocky Mountain Region	3.2	4.1
Pacific Region	2.6	2.1
West South Central (Texas + Southwest)	3.2	3.3

Source: Wharton U.S. Long-Term Outlook, June 1985, Wharton Regional Service Outlook, May 1985, and North American Electric Reliability Council, Electric Power Supply and Demand 1984-1993. Wharton's projections are average growth rates over the 10 years from 1984 to 1994.

Potential difficulties for utilities appear likely when average growth of demand over a long period differs from planned load growth. Wharton's projections are remarkably close to NERCs for the U.S. and indeed for most regions, suggesting that on a national basis, utilities have planned to generate or purchase sufficient power to meet demand requirements. On a regional basis, several potential problems appear in terms of demand growth expectations.

Wharton expects substantially faster growth in electricity demand in the Mid-Atlantic and South-Atlantic than do the utilities in those regions. In both these regions, utilities expect to meet part of the growth in demand with renewed growth in oil-fired generation, from 1987 onward. If demand growth is indeed significantly faster than these utilties expect, they are likely to need to make use of even greater amounts of higher-cost oil-fired generation. Alternatively, these utilities will have to purchase more power from regions with excess generating capacity. In the case of New York state, this will imply increased electricity imports from Canada, beyond currently planned levels. Wharton expects, however, that the need for greater generating capacity in the 1990s will be clear in time to increase capacity or to contract for the extra power; lead-time on oil-fired projects is substantially less than for coal- fired plants. Thus Wharton does not expect significant interruptions or rolling brownouts in the 1990s.

Greater use of purchased power and oil-fired generation could imply increases in the real cost of electricity in the early 1990s. Nationwide, however, baseload generating capacity should be adequate to meet demand growth. In fact, Wharton's projections suggest that planned investment will create surplus capacity in the East South Central and West North Central census regions.

NERC states in their supply/demand summary that 15 megawatts of generating capacity are scheduled to be retired over their ten-year forecast horizon. More than half of these retirements are of gas-fired units, with most of the remainder oil-fired. Wharton expects that actual retirements may be less than this amount, in light of financial and regulatory pressures to meet growth in summer peak demand without major capital outlays on new coal-fired generation.

Electric utilities do have an incentive to pursue a strategy of capital minimization. Many utility executives once proclaimed the need for ambitious construction programs to meet anticipated demand and replace more expensive oil-fired units. These same utilities have been delaying or canceling their construction projects, at a significant cost to consumers and stockholders. Utilities are now much more willing to rely on purchased power and third-party financing schemes than to undertake new construction projects.

There are a number of factors contributing to the utilities' incentive to minimize their investment in new central-station generating plants. High interest rates have increased the cost of borrowing for new investment over the past several years, and real interest rates are expected to remain high by historical standards for several more years, given prospective U.S. fiscal and monetary policy.

Utilities began major investments in new capacity in the 1970s, in anticipation of load growth which never materialized. Capacity utilization rates in the electric utility industry fell from 52 percent in 1972 to 40 percent in 1983. Given current comfortable reserve margins for most utilities, there is not immediate pressure to add capacity to increase reliability of service. Expected growth in electricity demand is nowhere near as fast as in earlier decades, and this too has led to a slowdown of investment plans.

Investments in base plant currently underway are not sufficient in some regions to meet projected baseload demand in the early 1990s. Yet the lead time for a new coal plant is 8 years. To avoid costly use of oil-fired capacity, a few new investments in coal-fired plants should be in the planning stages now.

New baseload investments are not planned for the near future, and one major reason is the phenomenon that Peter Navarro of Harvard calls "rate suppression". Rate suppression occurs when Public Utility Commissions fail to set electricity prices that keep pace with energy and capital costs, causing real earnings to fall below the industry's cost of capital. When earnings fall below the market rate of return, every dollar that a utility invests in fixed capital loses money, compared with the alternative option of bond purchases or retirement of debt.

A related regulatory problem is the "used and useful" criterion used by PUCs to determine whether a new plant can be included in the rate base. A number of PUCs have not allowed construction costs of new plants, in whole or in part, to enter the rate base — on grounds that they do not increase reliability by the "used and useful" criterion. In some cases these plants were economically desirable nonetheless, in reducing the average cost per kilowatt-hour of electricity generation. Unfavorable decisions in many such cases have tended to form an adversarial atmosphere between utilities and PUCs. Some utilities feel that their stockholders are being forced to bear all of the risk of construction decisions -- a view consistent with the "sufficient prudence" criteria sometimes mentioned in rate cases.

Rate suppression and the shifting of the burden of risk have together served to increase the difficulty for utilities in raising capital to finance new generating units.

The "rate suppression" decisions made by a number of state utility commissions are an important element behind the reluctance on the part of public utilities to invest in new plant. The utility industry has in fact given an answer to economists concerning the investment strategy that will result from inadequate returns. That strategy is an underinvestment in new central station generating plant, underinvestment in the conversion of less efficient units and underinvestment in conservation efforts. The cost of this strategy will be seen in the 1990s, when much of the added capacity will be expensive oil and gas-fired plants. Thus if the institutional forces which suppress rates do not moderate, consumers may well face higher rates, and the economy may face greater dependence on imported oil. Service interruptions and rolling brownouts can probably be averted with investments in oil-fired capacity, which has a relatively short lead-time.

The responsibility for decisions concerning electric power supply should reside with both the local PUCs and the utilities. Such joint decision-making should probably be accompanied by risk-sharing between stockholders and ratepayers. For a joint relationship to work effectively, several changes would have to occur:

- The adversary relationship between PUCs and utilities would have to be replaced.
- PUC staffs would have to be expanded, to facilitate the development of viable supply strategies, with PUCs responding to economic issues as well as political pressures.
- The "used and useful" and reliability criteria would have to be modified to consider cost-saving investments, and not simply investment to meet load growth.

Senator EVANS Thank you.
Mr. Smith.

STATEMENT OF STEPHEN A. SMITH, SENIOR VICE PRESIDENT, McGRAW-HILL PUBLICATIONS CO., DIRECTOR, ENERGY PRODUCTS GROUP, DATA RESOURCES, INC.

Mr. SMITH. Mr. Chairman and members of the committee, my name is Steven Smith. I'm a senior vice president of McGraw-Hill Publications Co., and in this position I'm responsible for the energy forecasting activities of Data Resources.

For approximately 10 years, we've routinely published on a quarterly basis long-term outlooks for the supply and demand of U.S. energy. Using Dan Dreyfus' terminology, our approach is very much a bottoms-up approach. We deal with individual fuels, individual regions of the country, and individual sectors of the economy.

The issue before the hearing today is to consider the potential for serious regional shortages of electric power by the early 1990's. This question is easier to pose than to answer. The difficulty stems from two principal uncertainties:

First, growth in load demand is much more difficult to estimate than in the past; and second, the rules of the game for utility management are in a state of flux. I will direct most of my comments today to an elaboration of these uncertainties and only briefly focus on the forecast. In many ways, learning to efficiently deal with this new level of uncertainty is the central problem facing both utility management and those responsible for utility regulation.

Forecasting problem No. 1 is that the utility industry is in a period of discontinuity. From 1950 to 1973, electricity demand showed reasonably stable growth, roughly 3 percent stronger than GNP growth, real GNP growth; and during this period lead times were predictable for new powerplants, costs of new units were predictable, and electricity prices were flat or even declining in real terms.

Beginning in 1973, a series of shocks occurred, and these were particularly focused on the utility sector. There was the pair of OPEC oil price shocks, there was extremely high interest rates, having a particularly strong effect on a capital intensive industry, and finally, there was what might simplistically be called the Three Mile Island shock. That shock should be more broadly viewed as the collection of events which led to nuclear lead times extending to 15 years and rate base additions for certain new nuclear units as high as $5 billion, or at least approaching $5 billion.

These three shocks combined to produce a dramatic increase in the price of electricity in the decade following 1973. Higher energy prices in general, along with foreign competition, also contributed to a significant compositional shift in the U.S. economy. This shift drastically curtailed the growth of electricity and energy intensive heavy industries.

As a result of higher electricity prices and a less energy intensive economy, electricity demand growth dropped sharply as compared with pre-1973 rates. I should add parenthetically, even though it's dropped sharply, for the last 10 years electricity demand has kept pace with GNP.

The last decade's discontinuity in electricity prices and growth has had far-ranging impacts. Despite numerous cancellations of powerplants in recent years, the momentum of the construction program has still resulted in new plants coming on line in a time when reserve margins were more than adequate.

It has also created considerable uncertainty about the rate of future electricity growth. The reason for the uncertainty is that there's little historical precedent to draw on. The country has never previously experienced electricity price increases such as those of the past decade, nor has it seen, other than in the Depression, a major restructuring of the entire industrial economy.

Low growth believers argue that capital stock—the capital stock replacement process is slow, and that this and new technology effects and shifts to a less energy intensive mix of economic output will be at work for years to come. The net effect, they would argue, is that growth will be—electricity growth will be 0 to 2 percent a year and it will substantially lag real GNP growth.

Other low growth variants allow for modest growth in end use electricity consumption, but discount the need for large capacity additions for U.S. electric utilities because of factors such as cogeneration, small hydro and wind power, and a substantial growth in imported Canadian power.

Believers in higher growth argue that much of the restructuring of the U.S. economy towards a mix of output which is less energy intensive has largely already taken place. Further, they would contend that excess utility generation capacity already reflects to some—already reflected in current electricity price, argues for flat or maybe declining real prices for electricity in the next decade.

Flat or lower prices, plus continued Sun Belt shifts, favorable electricity heat pump economics, new products which require electricity, would lead to electricity growth which at least keeps pace with GNP. A few high growth forecasters argue for rates as high as 3 to 4 percent.

Now, that's where the range of uncertainty lies. Basically, you can take your pick between 0 percent—I guess some go less than 0, and some go as high as 4 or slightly over 4. So with such a high level of demand uncertainty, there is a strong incentive for a utility to think long and hard before starting a new powerplant. It is safest just to wait and gather more evidence.

This brings us to the second forecasting problem: predicting the response of utility management now that the ground rules are in a state of flux. Let me state the problem faced by utility management. How attractive is it to build a plant under these conditions?

One, deal with over 50 State, local, and Federal agencies whose rules can change in midstream and sometimes retroactively.

Two, spend 8 to 12 or maybe 15 years in the process for a major base load unit, and if this obstacle course is completed and the plant is actually built, you may or may not get a return. Put another way, not only are safety and environmental rules constantly changing along the way; the financial rules of the game are changing.

State PUC's, feeling the political heat from sharp price runups and excess capacity, have been looking for culprits, and they've been revising the rules retroactively in this process. To earn a rate base return, a powerplant not only must be judged used and useful, but in many ways now must also be judged, with the power of hindsight, to have been prudent as well.

As might be expected, hindsight prudence lies in the eyes of the beholder. The sudden wave of prudency hearings after decades of no such hearings severely strains statistical odds. Could this many utility managements, after years of prudence, have all become imprudent simultaneously?

Whatever the answer, it has become abundantly clear that the rules of the game have been drastically altered. Under the new rules, if best judgment leads to construction of a plant which is excess in some sense, it may or may not earn a return. This change substantially alters utilities relative penalties for being long versus being short. The inevitable and logical response to this shift is for the utility to now pursue a course which has greater odds of being short.

Since investments requiring new shareholders' equity now face highly uncertain prospects for recovery, it is most logical for utility managements to pursue capital minimization strategies. To pursue any other course would result in continued dilution of shareholder equity.

One natural consequence of the new rules is that there is now a stronger incentive to be correct in assessing capacity requirements. This in turn suggests utilities will now shift their preference to a set of new capacity options which have shorter lead times. This implies minimizing green field sites, smaller rather than larger coal units, more favorable economics for refurbishing existing oil and gas-fired units.

Many of these options could have the end result of producing more costly electricity than would have been the case with large-scale coal units or with nuclear units in an improved regulatory environment. In addition, with many utilities now waiting as long as possible before adding capacity, the odds increase that some will inevitably wait too long and shortages result.

Having set the stage with the basic difficulty of forecasting and seeing this as an essential part of the problem facing the industry, let me simply briefly describe our forecast. I'd like to spend as little time as possible on the forecast. With a range of uncertainty of 0 to 4 percent, you have great odds of being wrong. It's simpler to talk about the problems.

We have very detailed models and we know all of their limitations, and we build them from the bottom up, sector by sector and region by region. And our basic end result goes something like this.

The DRI macroeconomic forecast expects trend growth over the next 10 years of about 2.9 percent per year in real GNP. A very detailed bottom-up approach leads to electricity growth which just about keeps pace with real GNP, about 2.9 percent over the next 10 years.

Since we deal with it by region, we do have regional rates that range from about 2 percent to some regions where growth is about

3.5 percent. In certain regions, in about two of nine census regions, we do show moderate shortages by 1995.

The inherent forecasting uncertainty is such that the two we've picked for shortages might be two in which there's adequate capacity and two others might be short. The key point—this is really not the key point—the key point is existing regulatory framework, broadly defined, has obviously certain obvious deficiencies. Without improving the system, an environment exists where some moderate shortages and/or unnecessarily expensive power alternatives are likely to develop by the mid-1990's.

Most importantly, left unchecked, these early problems of the midnineties have the potential to become far more widespread and serious in the post-1995 period.

Now, that concludes my comments. Thank you very much.

[The prepared statement of Mr. Smith follows:]

DRI Data Resources, Inc.

STATEMENT OF

STEPHEN A. SMITH
Senior Vice President,
McGraw-Hill Publications Company
Director, Energy Products Group
Data Resources, Inc. (DRI)

Before the
Committee on Energy and Natural Resources
United States Senate

Oversight Hearing on the Potential for Serious
Regional Shortages of Electric Power in the U.S.
by the Early 1990s

July 23, 1985

INTRODUCTION

Mr. Chairman and members of the committee:

My name is Stephen A. Smith. I am a Senior Vice President of McGraw-Hill Publications Company. In this position, I am responsible for the energy forecasting activities of Data Resources, Inc. (DRI). The DRI Energy Service provides energy forecasts to a wide range of clients including major oil and gas firms, electric and gas utilities, industrial firms, financial institutions, consulting firms and governmental agencies.

For approximately ten years, we have routinely published, on a quarterly basis, long-term outlooks for the supply and demand of U.S. energy. These forecasts are developed by fuel type, by sector of the economy and by U.S. census region. A summary of DRI's energy forecast is usually included for comparison purposes in the DOE's Annual Report to Congress.

The issue before the hearing today is to consider the potential for serious regional shortages of electric power by the early 1990s. Clearly the outcome could have a significant influence on the prospects for economic growth, and on the ability of the United States to remain effective in an increasingly competitive international marketplace. To frame the question a little more specifically, I will focus on one specific year and ask "what are the odds of serious regional electricity shortages by 1995, assuming that a business-as-usual macroeconomic, energy and regulatory climate prevails?"

This question is easier to pose than to answer. The difficulty stems from two principal uncertainties: (1) growth in load demand is much more difficult to estimate than in the past; and (2) the rules-of-the-game for utility management are in a state of flux. Each of these uncertainties is discussed in the following sections.

Forecasting Problem Number 1: A Period of Discontinuity

In the period 1950 to 1973, electricity demand showed reasonably stable growth, at a rate roughly 3% stronger than real economic growth. During this period, lead times for the construction of new power plants were typically four to six years, costs of new units were fairly predictable and electricity prices were flat or declining in real terms.

The "contract" between utilities and their regulators was well understood. Utilities were granted an exclusive regional charter, and required to supply all electricity demanded by customers in their region. In return, utilities were assured a "reasonable" return on "used and useful" facilities.

Beginning in 1973, and continuing through to the early 1980s, several external "shocks" combined to induce a series of secondary shock waves throughout the entire U.S. economy. Both the primary and secondary shocks had a particularly concentrated impact on the U.S. utility sector. The first shock was OPEC prices and this came in two stages. It produced, along with regulatory changes, sympathetic price increases for natural gas and coal. The second price shock experienced by electric utilities was partially induced by inflationary pressures of both the oil shocks and the resultant monetary policies which ensued. This led to extremely high interest rates and dramatically higher costs of capital for the capital-intensive utility sector. The third shock might be called the Three Mile Island shock for the sake of simplicity. It should be more broadly viewed as the collection of events which led to nuclear lead times extending to fifteen years and rate base additions for certain new nuclear units as high as $5 billion.

These three shocks combined to produce a dramatic increase in the price of electricity in the decade following 1973. Higher energy prices in general, along with foreign competition, also contributed to a significant compositional shift in the U.S. economy. This shift drastically curtailed the growth of electricity/energy intensive heavy industries. As a result of higher electricity prices and a less energy intensive economy, electricity demand growth dropped sharply as compared with pre-1973 rates.

This compositional shift in U.S. GNP coincided in part with the 1980-1982 recession, which made the task of sorting out permanent or "structural" impacts from the cyclical recession effects an extremely difficult task. With the economic recovery of 1983 to 1985, more evidence has become available. The degree of resilience in energy demands in response to economic growth has differed substantially by energy type. At one extreme, heavy fuel oil demands have continued to decline sharply as 'momentum" substitution effects continued. At the other extreme, electricity demand has not recovered to the "GNP plus 3%" levels of the 1960s but it does appear to be keeping pace with real GNP growth.

The last decade's discontinuity in electricity prices and growth has had far ranging impacts. Despite numerous cancellations of power plants in recent years, the momentum of the construction program has still resulted in new plants coming on-line in a period when reserve margins are more than adequate. It has also created considerable uncertainty about the rate of future electricity growth. The reason for the uncertainty is that there is little historical precedence to draw on. The country has never previously experienced electricity price increases such as those of the 1973-1983 period, nor has it seen, other than during the depression, a major restructuring of the entire industrial economy. Low growth believers argue that the capital stock replacement process is slow and that conservation effects, new technology effects and shifts to a less energy intensive mix of economic outputs will be at work for years to come. The net effect, they would argue, is that electricity will grow at zero to 2% per year, and it will substantially lag real GNP growth, which is likely to be in the 2.5% to 3.0% range.

Other low-growth variants allow for modest growth in end-use electricity consumption but discount the need for large capacity additions for U.S. electric utilities because of factors such as cogeneration, small hydro and wind power projects, and substantial growth in imported Canadian power.

Believers in higher growth argue that much of the restructuring of the U.S. economy towards a mix of output which is less energy intensive, has largely already take place. Further, they would contend that excess utility generation capacity (already reflected in current electricity price) argues for flat or maybe declining real price increase for electricity in the next decade. Flat or lower prices, plus continued sunbelt shifts, favorable electricity heat pump economics, and new products which require electricity, will lead to electricity growth which at least keeps pace with GNP. A few high growth forecasters argue for growth rates as high as 3% to 4%.

The range of uncertainty in load growth forecasts is likely to narrow in the next few years. However, if the evidence of the next few years proves the high-growth believers to be right, then the possibility of regional shortages becomes more pronounced but not inevitable. The following sections elaborate on this theme.

Forecasting Problem Number 2: The Rules of the Game are Changing

The first forecasting problem might be described as the difficulty related to major price and structural discontinuities and the demand growth uncertainties associated with these effects. The second problem relates to the difficulty in predicting the response of electric utility management given that the "ground rules" now seem to be in a state of flux. This second problem is clearly a derivative of the first.

The original "contract" between the electric utility, and its regulatory group was straightforward:

> Provide power to all who demand it and receive a "fair" return on equity employed in "used and useful" capital facilities.

This agreement worked well in the "steady state" days prior to 1973. Load growth was predictable and real electricity prices were declining. The series of exogenous shocks beginning in 1973 led to dramatic price increases, a sudden drop in demand growth, and substantial excess capacity. Regulatory bodies, feeling the political heat from an irate constituency, began to unilaterally and retroactively, change the rules.

To earn a rate base return, a power plant must not only be "used and useful", but now in many ways, must also be judged, with the power of hindsight, to have been "prudent" as well. As might be expected "hindsight prudence" lies in the eye of the beholder. The sudden wave of "prudency hearings" after decades of no such hearings, severely strains statistical odds. Could this many utility managements, after years of prudence, have suddenly become imprudent simultaneously?

Whatever the answer, it has become abundantly clear that the rules of the game have been drastically revised. Under the new rules, if best judgement leads to construction of a plant which is "in excess" in some sense, it may or may not earn a return. This change substantially alters the utility's relative penalties for being "long" versus being "short". The inevitable and logical response to this shift is for the utility to now pursue a course which has somewhat greater odds of being "short". Since investments requiring new shareholders equity now face highly uncertain prospects for recovery, while higher fuel costs will continue to see full recovery, it is most logical for utility management to pursue "capital-minimization" strategies. To pursue any other course would result in continued dilution of shareholder equity.

One natural consequence of the new rules, is that there is now a stronger incentive to be correct in assessing capacity requirements. This, in turn suggests that utilities will now shift their preference to a set of new capacity options which have shorter lead times. This implies minimizing green field sites, smaller rather than larger coal units, and more favorable economics for refurbishing existing oil and gas-fired units. Many of these options could have the end result of producing more costly electricity than would have been the case with large-scale coal units, or with nuclear units in an improved regulatory environment. In addition, with many utilities now waiting as long as possible before adding capacity, the odds increase that some will inevitably wait too long and shortages result.

Summary

Two forecasting problems have been discussed: first, the increased uncertainty of demand forecasting as a result of post-1973 exogenous price shocks and structural demand changes; and second, the new and evolving "contract" between utilities and their regulators. The two problems are closely related. The exogenous price shocks and the resultant uncertainties have increased the inherent risk in the total system. The regulatory agencies have responded by retroactively amending the old "contract", effectively shifting some of the increased system risk to the utility. Thus far, the regulated returns have not been adequately increased to be consistent with the higher levels of risk now facing the shareholders. The marginal equity investor can demand a higher return for this new level of risk. Utility management can meet this new equity capital need only by diluting the equity of existing shareholders. In this environment, utility management maximizes return to existing shareholders by minimizing capital investment. Failure of the regulatory agencies to provide returns commensurate with risk-appropriate free market returns results in distorted relative factor cost signals to utility management. "Capital costs" as seen by the utility include not only actual costs of more expensive new debt and equity but also the less obvious but real cost of dilution for existing shareholders. This biases the utilities' options toward those which employ less capital. Such a result is clearly a departure from economic optimality and ultimately both ratepayers and shareholders pay for the misallocation of resources. The practical effects of this course are that capital-minimization strategies are likely to increase the use of low lead time, higher fuel cost units, with increased risk that capacity additions may be "too little and too late".

DRI'S ELECTRICITY FORECAST

The prior sections have basically "set the stage" and provided the framework in which our forecast is developed. Some details of DRI's macroeconomic and energy forecasting systems are provided in Appendix A. There are three key components to the forecast.

(1) What is the likely trend course of real economic growth?

(2) What is the ratio of electricity growth to real GNP growth?

(3) How does regional electricity generation capacity change relative to load growth?

Macroeconomic Growth

DRI's current long-term trend forecast expects real economic growth of 3.3% per year between 1985 and 1990, and 2.5% per year between 1990 and 1995. The ten-year composite is annual growth of 2.9%. This is premised, among other things, on moderately declining real oil prices through 1990, followed by modest real increases for 1990 to 1995. Given all uncertainties which could influence this forecast, a reasonable range for ten year growth would be plus or minus 0.5%, or a range of 2.4% to 3.4%.

Electricity Growth

The growth rate for electricity is determined by analyzing the competitive position of electricity with other fuels in the residential, commercial and industrial sectors. This is done on a regional basis in that regional demographics, income growth and relative fuel prices and availabilities differ considerably. Regional prospects for cogeneration and imported Canadian power are also factored in. A number of judgemental assumptions, particularly on the rate of efficiency gains and penetration rates for new technology, can have a substantial bearing on the outcome. Our base case result is that U.S. electricity generation grows at a 1985-1995 compound annual rate of 2.9% or roughly the same rate as the growth rate for GNP. This relatively strong growth for electricity is compared with other national energy demands in Exhibit 1. The sectoral composition of national electricity demand growth is shown in Exhibit 2.

The projected 2.9% growth rate compares with a 3.1% annual electricity growth rate for the 1975-1985 decade. In both decades, electricity demands grew at roughly the rate of real GNP. However, the 1975-1985 period saw real annual electricity price increases of 2.7% whereas the decade ahead is likely to see 1% real annual declines. Despite declining real prices, electricity demands are not forecast to exceed real GNP growth because the level of real electricity prices, while declining, is still high. The growing use of more efficient stocks is expected to partially offset increasing market penetration effects.

Defining Shortage Severity

One problem in quantifying the possibility of regional power shortages is the absence of a standard measure. To aid in the discussion of our results, we have introduced a very rough measure which is called the "Shortage Severity Index". This is defined in Exhibit 3. This scale ranges from a value of zero (no shortages) to 5 (major loss of regional economic output and employment).

Possibility of Regional Shortages

The possibility of power shortages in the decade ahead must be analyzed on a regional basis. Projected regional electricity growth rates and reserve margins are summarized in Exhibit 4. Regional reserve margins are computed as the percentage by which capacity exceeds the regional peak load. For individual utilities a reserve margin of 20% is usually considered adequate to cover both planned and unplanned outages. When compositing to a regional basis it is probably more reasonable to use 20% to 25% in that intra-regional "pooling" capabilities and the extent of inter-regional ties differ considerably by region. Further, it must be noted that nameplate capacity in place in 1985 contains a higher percentage of relatively old and/or "economically obsolete" units than was typically the case when the 20% guideline was deemed to be adequate.

DRI's base case projections for regional growth suggest that shortages are most probable in the New England region and in California. New England's problems stem from a combination of DRI's higher than national average load growth projection plus our assumption that the current regulatory climate will prevent the needed completion of Seabrook 1. New England is projected to reach a reserve margin of only 1% by 1995 and experience level 2 shortages (using DRI's definition). The "West" region includes the Rocky Mountain regions and California. Again, higher than national electricity growth rates leads to a projected 11% reserve margin by 1995 with level 1 or 2 shortages expected primarily for California.

Sensitivity Analysis

As described previously, many uncertainties should be considered. The key uncertainties are trend macroeconomic growth and electricity growth per unit of real GNP. These effects could easily swing regional electricity growth by plus or minus 0.5% about our base case, or even by 1%.

A second major uncertainty is the rate of retirement for older fossil fuel units. Our base case would have to be described as "slow" in retiring older units. We have made the assumption that these older units may be viewed as "insurance" and held for possible refurbishing if demand growth should be stronger than expected. With the current "capital minimization" philosophy this approach is clearly favored over the risk of constructing an expensive new unit with questionable need and questionable equity returns.

Alternative A explores the consequences of 1% stronger demand growth in each region. (Exhibit 5) Alternative B explores retirement of an additional 10% of 1985 oil and gas capacity (12% was retired in the base case). Alternative C retires another 10% of 1985 coal capacity. Alternative A clearly has the most dominant impact. In this case, all but two regions could be expected to see at least occasional shortages by 1995 and the impact for New England could be severe. This case implies national electricity growth of 3.9%, which is possible but less likely. Alternative B worsens the shortage expected for New England and California but other regions maintain adequate margins through 1995. Alternative C leads to tighter but still adequate reserve margins in the coal-fired regions.

SUMMARY AND CONCLUSIONS

For certain regions and for certain utilities, serious shortages of baseload generating capacity appear quite likely by 1995, under the present regulatory framework. In the period 1995 to 2000, such shortages are likely to increase both in severity and in terms of the number of regions affected. In the early phases of this process, alternatives and emergency measures will keep the shortages from reaching severe levels, but only with attendant increases in costs. As "potential" shortages become more severe and regionally more widespread even the more costly alternatives will be exhausted and ultimately consumers will be adversly impacted.

The range of forecasting uncertainty is such that, if low growth prevails, selected regional shortages could possibly be avoided until after 1995. However, we would place the greater odds on having some regional problems by 1995. The more serious concern should be the post-1995 period. Efficiently sized facilities have long lead times. A "capital minimization" strategy is understandably being practiced in certain utilities. Unless the regulatory framework is modified to provide more "balanced" signals to utility management, the prospects are strong for widespread and significant shortages in the post-1995 period.

Exhibit 1

U.S. Energy Outlook: Base Case Outlook

	1965	1975	1985	1995	% Annual Growth 1965-1975	1975-1985	1985-1995
Primary Fuel-quads							
Oil	23.2	32.7	30.8	36.3	3.5	-0.6	1.7
Gas	15.8	19.9	18.3	19.0	2.3	-0.8	0.4
Coal	11.5	12.6	17.8	22.1	0.9	3.5	2.2
Nuclear	0.0	1.9	4.0	6.8	NM	7.7	5.5
Hydro/Other	2.1	3.3	4.2	4.5	4.6	2.4	0.7
Total	52.0	70.4	75.1	88.6	3.0	0.6	1.7
Real GNP (1972$ Billions)	929	1231	1687	2241	2.9	3.1	2.9
Thousand Btu/$ Real 1972 GNP	56.6	57.2	44.5	39.6	0.1	-2.5	-1.2
Electricity Demand-Billion Kwh	953	1733	2344	3112	6.2	3.1	2.9
Electricity Primary Fuels-quads	10.9	19.8	26.8	35.8	6.2	3.1	2.9
Electricity Primary Share of Total	21%	28%	36%	40%	NM	NM	NM
Non-electric Primary Fuels -quads	41.1	50.6	48.3	52.8	2.1	-0.5	0.9
Imported Oil Price $1985/Barrel	$7	$21	$27	$27	11.6	2.5	0.0
GNP Deflator	NM	NM	NM	NM	5.5	6.3	5.3

Exhibit 2

Base Case Forecast: Details of National Electricity

	1965	1975	1985	1995	% Annual Growth 1965-1975	% Annual Growth 1975-1985	% Annual Growth 1985-1995
Electricity Demand by Sector-Billion Kwh							
Residential	281	586	802	1008	7.6	3.1	2.3
Commercial	233	476	666	887	7.4	3.2	2.9
Industrial*	439	671	876	1217	4.3	3.0	3.3
Total	953	1733	2344	3112	6.2	3.1	2.9
Real GNP (1972$ Billions)	929	1231	1687	2241	2.9	3.1	2.9
Electricity per Real GNP, kwh per 1972$	1.03	1.40	1.39	1.39	3.2	0.0	0.0
Average Electricity Price, Nominal Cents/kwh (Average all regions, all sectors)	1.60	2.73	6.46	9.97	5.5	9.0	4.4
GNP Deflator	NM	NM	NM	NM	5.5	6.3	5.3
Real Electricity Prices, 1985 cents/kwh	4.95	4.95	6.46	5.90	0.0	2.7	-0.9

* Includes small amount of transportation and other uses.

Exhibit 3

Definition of DRI's Shortage Severity Index Levels

(Basis: Multi-State region which is summer peaking)

Level 0: No shortages or voltage reductions except for highly unusual equipment failure or weather.

Level 1: Voltage reductions or other mandatory load reduction programs required routinely for a few utilities in the region several times per summer. Most noticeable in hot summers.

Level 2: Certain utilities in the region have predictable and severe curtailments each summer. 10% to 25% of region's population measurably inconvenienced by load reductions.

Level 3: 25% to 50% of region's population routinely affected by brownouts, building temperature controls, etc. even in mild summers. Severe multi-day shutdowns for selected industrial facilities. Increased use of very expensive marginal units.

Level 4: 50% to 100% of region's population directly affected by cutbacks each summer. Industrial shutdowns common and widespread in summer months. Major inconveniences such as rotating brownouts, inadequate air conditioning, loss of productivity. Power availability now a major factor in plant location decisions. Regional GNP loss of 1% to 3% from shutdowns, productivity losses, more oil-fired generation etc.

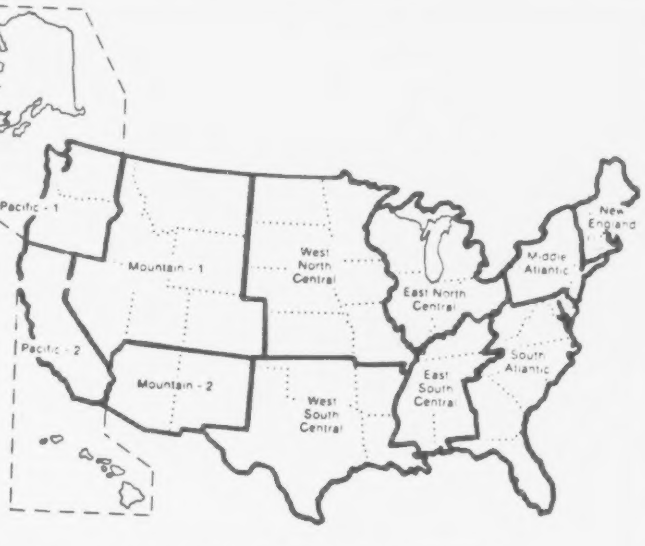
Level 5: Level 4 worsened and sustained. Regional GNP effects of 3% to 10%; "OPEC" sized crisis.

Exhibit 4

DRI Base Case: Forecast of Regional Load Growth and Reserve Margins

	1985-1995 Electricity Demand of Growth	Reserve Margins			1995 Shortage Severity Index
		1985	1990	1995	
New England	3.2	0.52	0.23	0.01	2
Mid-Atlantic	2.9	0.68	0.56	0.34	0
South Atlantic	2.8	0.52	0.40	0.30	0
East North Central	2.9	0.70	0.55	0.35	0
West North Central	2.0	0.64	0.52	0.42	0
East South Central	2.9	0.53	0.37	0.29	0
West South Central	2.7	0.45	0.40	0.34	0
Pacific 1	2.8	0.61	0.50	0.42	0
West	3.5	0.30	0.21	0.11	1-2
U.S.	2.9				

Energy Demand Regions


Pacific - 1
Mountain - 1
West North Central
East North Central
Middle Atlantic
New England
Pacific - 2
Mountain - 2
West South Central
East South Central
South Atlantic

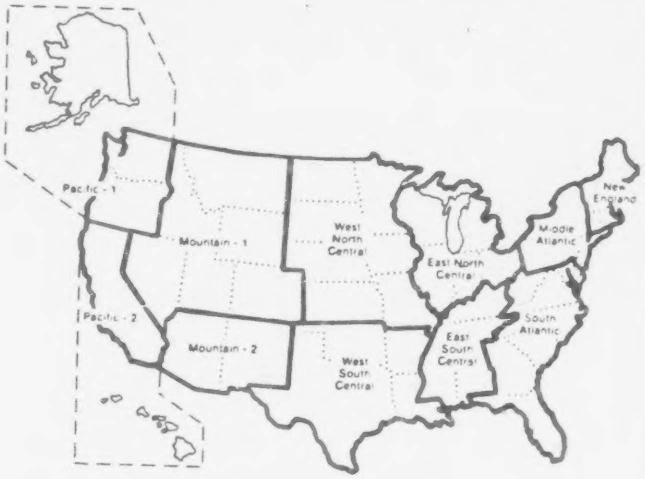
Note: The "West" region includes Pacific 2, Mountain 1 and Mountain 2.

Exhibit 5

Comparison of Base Case With Alternatives

	Base Case			1995 Values					
				Alternative A		Alternative B		Alternative C	
				1% Higher Regional Load Growth		Additional 10% of 1985 Oil/Gas Capacity Retired		Additional 10% of 1985 Coal Capacity Retired	
	1985-1995 Demand Growth	1995 Reserve Margin	1995 Severity Index	Reserve Margin	Shortage Severity Index	Reserve Margin	Shortage Severity Index	Reserve Margin	Shortage Severity Index
New England	3.2	0.01	2	-0.06	3-4	-0.05	3-4	0.00	2-3
Mid Atlantic	2.9	0.34	0	0.21	0-1	0.27	0	0.30	0
South Atlantic	2.8	0.30	0	0.17	1	0.27	0	0.24	0
East North Central	2.9	0.35	0	0.22	0-1	0.33	0	0.26	0
West North Central	2.0	0.42	0	0.29	0	0.39	0	0.33	0
East South Central	2.9	0.29	0	0.16	1	0.28	0	0.22	0-1
West South Central	2.7	0.34	0	0.21	0-1	0.27	0	0.31	0
Pacific 1	2.8	0.42	0	0.37	0	0.41	0	0.41	0
West	3.5	0.11	1-2	0.03	2	0.08	2	0.08	2

Energy Demand Regions


Pacific - 1
Mountain - 1
West North Central
East North Central
Middle Atlantic
New England
Pacific - 2
Mountain - 2
West South Central
East South Central
South Atlantic

Note: The "West" region includes Pacific 2, Mountain 1 and Mountain 2.

APPENDIX A

DRI's Energy Forecasting Methodology

DRI's forecasting process involves a series of inter-related models: (1) a long-term model of the U.S. macroeconomy (there are companion models for most other major countries); (2) a world oil model which balances world oil supply and demand and is used to assess world oil prices; (3) a detailed model of the U.S. energy economy; (4) a U.S. coal supply model; and (5) a U.S. oil and gas supply model.

The forecasting process is iterative. A world oil price is determined which is consistent with U.S., European, Japan and LDC macroeconomic growth. The U.S. energy model is "driven" by the world oil price and the long-term outlook for the U.S. economy. Energy demands are determined for each sector and for each fuel based upon projected economic growth. Population, housing stocks, and income growth are projected for eleven regions of the country. Electricity consumption in the residential sector is discussed below as an example of the forecasting process.

New home heating systems are determined for each region based on new homes plus replacement burners. Within each region the comparative life cycle costs of alternative heating/cooling combinations are determined. For example, gas furnaces plus electric central air is compared with a heat pump. Favorable economics for one system versus the other shift the regional market shares for competing systems. This process, year-after-year, leads to gradual shifts in the "stock" of heating systems of various types. Actual residential electricity consumption depends on the number of electric heating and cooling units in place, combined with "behavioral" equations which relate usage of stock-in-place to income and price effects. Comparable stock and utilitization models are employed to determine electricity demands for all sectors in all regions. The total electricity demand for each region influences generation mix. This mix, in turn, can influence price, and price influences demand. This "loop" is handled iteratively in the model.

The **Chairman** [presiding]. Thank you.

Dr. Farney.

STATEMENT OF DR. KEMM C. FARNEY, SENIOR ECONOMIST AND DIRECTOR, UTILITY ECONOMICS, CHASE ECONOMETRICS

Dr. **Farney**. Thank you, Mr. Chairman.

My name is Kemm Farney. I'm director of utility economics at Chase Econometrics. Chase Econometrics is a wholly owned subsidiary of the Chase Manhattan Bank, specializing in forecasting to industry.

In our view, there will be shortages of power in the 1990's. Based upon our regionalized model of electricity usage by residential, commercial, and industrial customers, we believe that domestic generating capacity, in order to preserve current standards of adequacy, must grow to 760 gigawatts by 1992.

In the 1984 NERC annual review, their statement of planned 1992 installed capacity is around 724 gigawatts. So you can see that, based upon our calculations of increments to capacity necessary to preserve current standards of adequacy, there is a shortfall.

The question as posed, however, was one of severe shortages, and I think that that's a value judgment that we all must make. I personally see the electric utility industry as being simply in transition. There will be shortages in particular service areas. Those service areas will be scattered geographically. In many cases they'll be contiguous to service areas where there are no problems.

When I think of shortages in the electric power industry in the early nineties, I think in terms of higher prices for electricity, in terms of changed marketing strategies—for example, discouraging large new power users from connecting to the grid—and only as a last situation do I see a noticed degradation in the quality of service.

So that for me this transition is a period—is a transition from a period when the lights went on every time you threw the switch to a period where there was a chance that the lights might not go on when you threw the switch, but you could count on that being only at particular times of the day and then only during particular times of the year.

If you compare today's standards for adequacy with the standards of 20 years ago, I think we all remember that those standards from 20 years ago were one loss of load event in 10 years. Today's standards are substantially less than that, and my feeling is that over the next decade or two decades those standards will evolve further.

There are three indicators that can be used for identifying those service areas where shortages of this type are likely to occur. The first indicator that I use is that cash interest coverages, which are heavily influenced by the expenditures on capital investment, cash interest coverages will fall in the future or are falling and have fallen now.

In the simulation work that I've done, I've found that it's not infrequent for a simulation of a utility's balance sheet and income statement as that utility executes their stated capital expansion plan to fall very near 1. A cash interest coverage of 1 means that cash income is barely sufficient to pay your interest expense. What that really means is that some of those plants at least won't be built.

The second indicator that I look for is a change in the stated capital expansion plan. Typically, this looks something like eliminating a base load unit and adding a number of combustion turbines. It may be an added less capacity, but certainly—or it may be the same added capacity, but certainly it's capacity with lower front-end cost and the necessity of financing construction work in progress is reduced.

And the last indicator that I look for are the kind of things that appeal to a casual empiricist, things like bill stuffers sent to customers explaining what to do in the event of a brownout or a loss of load.

I think that there are really three important reasons why this situation is occurring. They all focus on one particular interest held by regulators, and that is to control the escalation of prices paid by consumers for electricity.

The first is an interest in forecasting, particularly whether past forecasts support a presumption of prudent decisions. I think that these reviews of past forecasting are really unfair for three reasons.

First, forecasting as we practice it today hasn't existed for very long. You have before you representatives from WEFA, GRI, and Chase Econometrics. All three companies began their work as industrial luminaries in the very, very late sixties and very early seventies. The procedures that we use in forecasting I did not see enter the electric utility industry until 1977 or later.

Even today, an individual who has the technical skill to prepare a forecast on a 20- or 30-year time horizon is exceedingly rare. It's a very different skill than the skill involved in preparing a 10 quarter forecast of the disposition of personal income and investment.

Second, during the decade of the seventies the U.S. economy went through a transition from the relatively rapid growth that we had in the sixties to slower economic growth, and I think that forecasts were adaptive and in many cases it was the macro forecast which caused the peacock's tail in the load forecast. That's not the only reason, but that certainly must have been a factor.

And third, historically there has always been a recognition that there is a high social cost to insufficient capacity—this is the old iron lung argument—a high social cost to insufficient capacity and a relatively lower social cost to too high generating capacity, and as a result it's rational, it's perfectly rational, although I would never argue that it was done deliberately, but it is perfectly rationale for an electric load forecast to be too high, to reflect those skewed social costs.

The second area of interest by regulators that seems to be a partial cause of this transition is an increased review of the cost overrun experiences for management prudency. This is an area where I've done quite a bit of statistical analysis, and I would agree with the earlier witnesses that at least there's no statistical evidence to indicate that differences exist between the management of construction projects between companies.

The problems of the cost overrun experience seem to be tied to characteristics of the construction environment and not to the characteristics of construction management.

And finally, in the interest of holding down rates paid by consumers, there's an interest in keeping CWIP out of the rate base, and as a result it's the ratepayer who must bear the burden of the allowance for fund use during construction, and on large construction projects, as all constructing utilities face, that's a very large burden.

In summary, I'd like to repeat that in my view the electric utility industry is an industry in transition. Economic incentives have been laid such that the quality of service will decline somewhat, although it's unlikely that that would be very noticeable to most consumers. More likely, we're going to see higher prices and different marketing strategies.

This is a tradeoff which is not being made deliberately, but it is a tradeoff that's being made by an administrative process today.

[The prepared statement of Dr. Farney follows:]

United States Senate
Committee on Energy and Natural Resources

Oversight Hearings On the Potential For Electric Power Shortages In the 1990's

Testimony of Kemm C. Farney

Q. Please state your name and business address.

A. Kemm C. Farney, 150 Monument Road, Bala Cynwyd, Pennsylvania 19004.

Q. By whom are you employed?

A. I am employed by Chase Econometrics, Inc., a wholly owned subsidiary of the Chase Manhattan Bank.

Q. What position do you hold with Chase Econometrics?

A. I am Senior Economist and Director, Utility Economics.

Q. Dr. Farney, will you please describe your educational background and experience?

A. I recieved a Bachelor of Arts degree in 1973, a Master of Arts degree in 1974 and a Doctor of Philosophy degree in 1983, all from Florida State University. The subject of my doctoral dissertation was "Unanticipated Project Cost Growth (Cost Overruns) In Electric Powerplant Construction." From 1975 to 1978 I was enrolled in the doctoral program in Economics at the University of California at Santa Barbara. During the period 1973 to 1979, I was employed on a number of research projects as a research assistant and econometric consultant During this period I also taught Economics at Florida State University, the University of North Carolina at Charlotte, and the University of California at Santa Barbara.

In 1979 I joined the staff of the Research and Management Studies Department of the Florida Public Service Commission and served as Senior Economic Analyst until 1981. My principal responsibility in that position was the monitoring of demand and sales forecasting as conducted by the utilities operating in the state of Florida. In this capacity I assisted in the writing of proposed rule changes, reviewed the adequacy of forecasting procedures and the reasonableness of the resulting forecasts, and served as staff witness to present findings in areas related to sales and load forecasting.

In 1981, I joined the Utility Consulting Group at Chase as a Utility Economist. My responsibilities included work on the design, estimation and implementation of energy sales and peak demand forecasts and forecast models for utility clients, as well as consulting on a variety of projects related to the utility industry. In late 1983, I assumed the position of Senior Economist and Director, Utility Economics.

Q. What are your responsibilities as Director of Utility Economics?

A. I serve as project manager on all consulting projects relating to the utility industry, and as lead analyst on most of those projects. I also direct our quarterly Electric Utility Cost Forecasting Service which assists our electric utility clients in projecting operating, maintenance and construction costs.

Q. Have you testified in any other proceedings?

A. Yes, I have served as an expert witness in more than twenty five docketed proceedings, before the Florida Public Service Commission. the Iowa Commerce Commission and the Ohio Department of Development Division of Energy. I have offered testimony on the full spectrum of issues relevent to electric utility planning, including: electric sales and peak load forecasting; the economic need for new powerplants; the expected cost overruns associated with new powerplants; the economic implications of changing rate structures; the implementation of PURPA; appropriate incentives for utility conservation and the potential for industrial cogeneration.

I. WILL SHORTAGES OCCUR?

Q. Dr. Farney, will serious shortages of baseload generating capacity occur on individual utility systems by the early 1990's?

A. I believe that shortages of capacity will occur on some systems by the early 1990's. These shortages will most likely appear to consumers as: higher priced electricity; degradation in service during periods of peak system loads; and changes in utility marketing strategies, e.g., encouraging cogeneration or discouraging plans of new large power users to connect to the system.

Q. How severe will these shortages be?

A. Chase Econometrics projects, based upon our regionalized model of electricity usage by residential, commercial and industrial customers, that in order to provide adequate power supplies domestic generating capacity must grow from a 1984 level of roughly 675 gigaWatts of installed capacity to a 1993 level of roughly 760 gigaWatts. The required increment to total capacity is then 85 gigaWatts.

At the same time, the 1984 volume of the North American Electric Reliability Council's Annual Review of the Overall Reliability and Adequacy of Bulk Power Supply reports that electric utilities report that their plannedg 1992 installed capacity is 701 gigaWatts, down from a 1983 projection for 1992 installed capacity of 724 gigaWatts. Thus, utility plans fall short of our forecasted need by about 59 gigaWatts.

Q. How will troubled service areas be distributed regionally?

A. I believe that specific service areas will be effected. In many cases troubled service areas will be contiguous to service areas which are untroubled. Troubled areas will be generally well dispersed; I don't think there will be an area of the country in which difficulties are concentrated.

Q. Are there symptoms of coming power shortages that we can recognize today?

A. Yes, there are. They can be seen in three areas. First, for some utilities cash/interest coverages have fallen dramatically or will fall dramatically if they conduct their published construction programs. In simulation work which I have done, it is not uncommon for cash/interest coverages to fall near 1.0 before the completion of the construction program. A cash/interest ratio of 1.0 means that cash income is just sufficient to pay interest on debt.

Second, symptoms appear in published generation expansion plans. As the first symptom becomes increasingly apparent, utilities change the basic philosophy behind their plans. One change that has been made by some is to reduce or eliminate plans for construction of base load plant and to increase the importance of combustion turbines. Combustion turbines enter the rate base more quickly, reducing the obligation to finance Construction Work In Progress, but have higher running costs than base load plant. Ignoring the purely financial issues, they result in less efficient construction programs resulting in higher end use prices for electricity.

A second change which has been seen is the publishing of generation expansion plans which report planned negative reserve margins. The argument heard to support this change is that the utility is remaining flexible, prepared to exploit any opportuniy which may arise. The actual statement being made seems to be that the utility cannot see a way, given balance sheet conditions, to finance needed construction.

Third, the more readily observed behavior of the utilities provides additional clues. Some utilities are including bill stuffers advising customers on what to do in the event of a black out. Some utility executives will admit in private conversation that their balance sheet constrained capital expansion plans entail brown outs and black outs by the mid 1990's.

Recognize that none of this is taken lightly. Utility management is accustomed to a regulatory environment in which the common carrier requirement is interpreted, often by state statute, to be a requirement that the utility serve all of the load that appears on the system. Deviating from this standard involves difficult and painful decisions.

At the same time, regulators have a responsibility to impose regulation in a manner such that the firm remains whole. In each instance in which utilities plan to build less than the amount of new plant necessary to satisfy system reliability issues, the cause is an inability to build without jeopardizing the ability of the firm to remain whole.

II. CAN INTERRUPTIONS BE PREVENTED?

Q. Dr. Farney, can interruptions be prevented?

A. I'm optimistic that serious interruptions can be prevented. Remember that one of the symptoms of trouble which I mentioned was a tendancy to increase the importance of combustion turbines in expansion plans. For example, NERC's 1984 Annual Review reports that within ECAR (the East North Central Census region less several states plus several others) four nuclear units representing 3,600 megaWatts of capacity have been declared uncertain, while nine combustion turbines totaling 735 megaWatts have been added to construction plans.

In most cases, power will be available through altered construction programs involving a smaller financing burden, or through purchases of power. But this power won't be from sources which were carefully chosen to minimize rates paid by ratepayers. The decision process has been altered by a financing constraint caused by regulation.

Also, as I mentioned earlier, there will probably be some degradation in the quality of service, especially at the time of the system peak. This may not be the result of insufficient power in neighboring service areas that might be brought in, but rather because the transmission interties available may not be of sufficient size to handle the extra power wheeling.

III. ARE THERE INCENTIVES TO MINIMIZE INVESTMENT?

Q. Dr. Farney, do electric utilities have an incentive to minimize their investment in new central-station generating plants?

A. The answer to this question given the economic meaning of each term in the question is "No," but I may be quibbling over words here.

Regulation has made the construction of new facilities very risky. In business, risk is the probability that a cost will be incurred, so construction is therefore more costly. In order to survive, any businessman has an incentive to avoid risk, and utilities are no exception. Utilities do not have an incentive to minimize their investment per se. They do have incentives to manage their businesses rationally, managing the risk bearing activities such that the ongoing health of the firm is assured, and the ability of the firm to serve its customers is assured.

Q. What factors in regulation impose these increased risks on utilities?

A. Regulation is reactive. Most rate cases, for example, are brought by the utilities themselves, not by regulators or intervenors. Regulators, whether elected or appointed, have shown an interest in not allowing nominal electricity prices to rise (in the presumed interest of ratepayers). Their actions have reflected this interest in a group of efforts loosely grouped together as "rate suppression."

Q. What is Rate Suppression?

A. Rate suppression is that class of regulatory actions which have attempted to keep electricity prices paid by consumers today and in the very near future as low as possible. It is a set of short run interests, and will result in a higher growth path for end use prices over the long run than would otherwise be the case. It is characterized by a group of essentially finger-pointing activities such as: allegations of imprudence in the decision to build new plant when forecasted load growth has not developed; allegations of mismanagement by utilities when construction cost overruns have occurred; and a bias against finding solutions to the difficulties faced by utilities in financing the burdensome levels of Construction Work In Progress involved in generation expansion.

IV. DOES RATE SUPPRESSION CONTRIBUTE TO FUTURE SHORTAGES?

Q. Does rate suppression lead to future shortages?

A. It can, and I think it does. It makes the construction environment more risky and more expensive.

Q. Could you please give an example?

A. I mentioned three quite good examples immediately above. We can go through them one at a time. First, take the review of load forecasting activities for evidence of imprudence. The argument is that if forecasted load growth doesn't develope, the forecast was bad and decisions based upon it were imprudent. This argument ignores a number of key facts:

-Forecasting as practiced today didn't come into being until the very late 1960's and early 1970's. Modern forecasting techniques, to my knowledge, didn't begin to gain ground among utility planning shops until about 1977. Even today, forecasters with the training and experience to make projections twenty or thirty years into the future are quite rare. Extremely long range forecasting is quite similar to identifying Megatrends; it doesn't have much to do with short term business cycle related forecasting problems most planners must deal with.

-During the decade of the 1970's the United States economy went through a period of structural change, moving towards a slower growth path. Each year long range forecasts of economic growth were reduced, just as forecasts of peak load were reduced by the utilities (who like all of us were clients of the macroeconomic forecasters).

-There is a substantially higher cost of having too little capacity, compared to the cost of having too much capacity (the iron-lung argument). Given these skewed costs, it is rational for a forecast of peak demand to be too high, since it reduces the risk of planning for insufficient capacity.

A second example is the presumption held by some that construction cost overruns are symptoms of mismanagement, that some portion of cost overruns can be identified as unacceptable and should be excluded from rate base. Studies of construction projects have shown that less than 15 percent of unanticipated project cost growth is due to errors in the estimation of material or labor requirements. based upon statistical work I have done I believe that this ratio is about right for powerplant construction also.

The principal causes of unanticipated project cost growth are: errors in forecasting the rate of inflation; errors in forecasting the interest rate paid on borrowed funds; and errors in forecasting the gestation period for the project. The entire economy was victimized by the first two of these during the past decade, particularly the high capitalization industries like the electric utilities. The third item is not peculiar to the utilities, either. Most big construction projects, like the Trans Alaskan Oil and Gas Pipelines, various weapons projects, the Panama Canal, etc. have had too low estimates of time for completion.

In the case of utilities, particularly with nuclear construction, regulation has greatly increased the gestation period of projects unexpectedly. Often these delays were the result of required removal and replacement of concrete and steel already in place to satisfy new regulatory requirements. Additional cost growth has arisen because of shortages of skilled, experienced manpower resulting from projects being built by a number of utilities simultaineously.

Third, there is an unwillingness to assist the utilities in paying the capital carrying charges associated with the Construction Work In Progress account. The argument here is that it is the responsibility of the stockholder to support this burden. The argument overlooks the fact that the generation expansion plan may involve doubling the rate base in a decade. In these cases, it is rare that the balance sheet can support the investment burden. Add to this the lengthening gestation periods for plant construction, and the financing becomes impossible without the assistance of the ratepayer.

V. WHO SHOULD HAVE RESPONSIBILITY FOR PLANNING?

Q. Finally, Dr. Farney, who should have responsibility for planning?

A. Of all the issues involved, this is the most clear. Regulators do not have the skilled staff necessary to make the difficult and technical decisions involved in capital expansion planning. In many cases, regulators do not even have the skills required to competently review these plans. Unless we are prepared to make a tremendous investment in building this skill pool within the regulatory organizations, the planning responsibility must remain in the utilities corporate planning shops.

Q. Does this complete your testimony?

A. Yes, it does.

The CHAIRMAN. Thank you very much.

I think in our first round of questioning, we'll try to comply with the 10 minute rule, and I'll invite members to do better than that if they can and submit questions for the record to the extent that we can. This is the first of several panels to be heard today and obviously our time is somewhat constrained.

Let me start with you, Dr. Farney, and then work back across the table on a couple of rather general questions. If I understood you correctly, and I don't recall the exact terminology that you used, but you said there was a skewed evaluation of forecasts when it was assumed that there were high social costs in shortage and low social costs in surplus, if I understood you correctly.

Dr. FARNEY. If you look at the literature, say, published in the middle and late seventies on the costs of over and undercapacity, that literature states fairly clearly that there is a higher social cost to insufficient capacity than to excess capacity.

The CHAIRMAN. And did I understand you to say—to disagree with that, in effect?

Dr. FARNEY. No, sir, I do not disagree.

The CHAIRMAN. All right.

Dr. FARNEY. I'm simply pointing out that that alone would be sufficient to motivate a load forecast higher than what might be realized.

The CHAIRMAN. What is your opinion? Is it better to have surplus or better to have shortage?

Dr. FARNEY. I don't have an opinion in that area. I think that's a judgment.

The CHAIRMAN. Mr. Smith.

Mr. SMITH. The last question?

The CHAIRMAN. Yes.

Mr. SMITH. I think most people would agree that it's reasonable to maintain—this is basically the classic inventory problem: How many newspapers does the newsboy buy? If he buys too many he gets stuck with them at the end of the day.

The only problem here is that it's got about a 12-year lead time, which makes it a little complicated, and there's costs of being short and costs of being long. Obviously you would—if you design a system in which you never ever are long, you'd probably build too much power. What you'd like to do is design a system where you're trading off the cost of having this backup against the cost of being out, and normally the optimal would lead you to systems that have somewhere between 20 and 25 percent excess capacity, has been the normal industry practice; and I would think that you'd be trying to target for that range.

The CHAIRMAN. As I recall, there've been some who criticized having a spinning reserve as high as 20 percent, suggesting we get by with 3 to 5 percent spinning reserve. What happens when the lights go out? What happens in a brownout?

What are the social costs of an insufficient supply as compared to the social cost of building a larger reserve than is perhaps otherwise necessary? In other words, should we deliberately scale our utility system so that there are occasional brownouts, rather than pay the cost of avoiding those brownouts?

There's a cost either way.

Mr. SMITH. In my judgment, I don't think so. I think you should—that we have not seen electricity shortages, serious, ever in this country, aside from one or two isolated instances. We have seen natural gas shortages. They provide some indication as to the unforeseen nature and the surprisingly severe impacts of such shortages, such as closing of factories and lost unemployment, closing of schools.

So I think it doesn't take much imagination to visualize a situation in which you had planned for low growth and somewhat higher growth developed, and all of a sudden brownouts become blackouts and all of a sudden electricity availability starts to become a major factor in industrial facility location decisions and so forth.

I think obviously, or at least in my opinion, the traditional rules of the 1.2, 1.25, I would favor.

The CHAIRMAN. Dr. French, before asking you the same question, I would just parenthetically note that some appliances, home appliances, industrial equipment, demand stable supplies of electricity. Motors begin to burn out if low voltage occurs.

In some areas, if you have electric water heating and no natural gas, as an example, people could make the choice of keeping the refrigerator or air-conditioner running and turning off the water heater. In other places where they don't have that choice, then they may have hot water in the hot weather and no air-conditioning and perhaps the refrigerator motor burns out.

In New York City you might be able to say to everybody, turn off the air-conditioners and keep the elevators running, as an example.

What is the social cost calculation, or is there any way of making a calculation, of insufficient supplies as compared to the social cost of building an excess capacity that avoids brownouts?

Dr. FRENCH. I would say that most economists and most utilities, judging by their past investment behavior, are much more comfortable with some reserve margin above this 3- to 5-percent level. In particular, Mr. Smith's 20 to 25 percent has been a traditional rule in the past.

We could go beyond that and say that even 20 to 25 percent may not be the most socially beneficial excess margin for error on the part of electric utilities. In particular, a lot of the current comfortable reserve margin that we see is expensive oil-fired capacity. Now, it's very possible that you may be looking at considerably lower real oil prices in the 1990's and thus the real costs of generating via oil-fired capacity may not be as high.

Nonetheless, we're talking about the possibility that it may be economical and reduce the cost of electricity to expand output or to expand reserve margins in certain regions beyond this 20- to 25-percent level, just on a dollars-and-cents basis in terms of how much the final ratepayer actually pays.

So I would say definitely, I'm on the side that says we ought to be looking at considerably larger margins than 3 to 5 percent. Those social costs as far as I can see are very high.

The CHAIRMAN. Dr. Hogan?

Dr. HOGAN. Well, I'm grateful to Steve Smith for the newsboy example and I endorse it, and I think it does capture the essence of the problem.

I think also, as Dr. French just pointed out, that over the timeframe that we're talking about concentrating on shortages and lights going on is probably not the right problem to focus on, that it really is, as you said in your opening remarks, a question of cost; and if you do the things which are economically efficient today in order to back out higher cost generation, you'll also as a byproduct create lots of excess capacity to meet these peak demands, which are where you get these brownout kinds of problems.

And in any event, the peak demand problems don't last very long, and you can take action, expensive action, in order to alleviate those fairly quickly. So for planning today over a period of decades, what you're really talking about is the economics and the costs of the power that people are going to be buying.

The CHAIRMAN. Dr. Dreyfus.

Dr. DREYFUS. I'm afraid I have a different view on that. I think that the social cost is a question of from whose viewpoint you approach it. Traditionally, we had a system that worked pretty well, in the sense that the utility took on a utility responsibility to provide reliable, nondiscriminatory service, and the public utility commission had the responsibility to watch what they did and make sure that it wasn't extraordinarily expensive.

As long as that was going on, the question as to what social costs were appropriate to avoid rested with the technical guy at the utility, and in those years they placed a very high value on social costs and essentially had a fail-safe system to the degree that it was achievable.

Now, there was in that a guarantee that the uneconomic aspects would be returned to the investor by some kind of a rate structure that rewarded the provision against social costs. What we have now is, that system's been shaken up in a sack and the utility has been given signals that it will not be rewarded for costs associated with providing against the social costs.

We now face the question of who is the stakeholder that has to worry about social costs? Now, you can take one attitude, that from the utility's point of view it's what can you get a rate of return on, and you don't build any more than you can get a rate of return on. I think that's where we are today.

I think that's the reason you don't have new starts, and I don't think you're going to get any new starts until the reliability problem is manifest and the utility commissions are screaming for action. That guarantees that the rate of return will be appropriate.

There remains, I think, a public policy responsibility to contemplate the social costs, but that's going to have to be done by public entities.

The CHAIRMAN. If your scenario is correct, that guarantees future shortage, does it not?

Dr. DREYFUS. Given the lead times, I would say that in the direction we are taking, unless we are amazingly lucky and bailed out by some new unforeseen reduction in energy demand, yes. You're going to see ragged systems somewhere in the nineties. The only possibility that there might not be a significant problem is that the early horror stories might be adequate to result in a change in attitude and resurgence of investment.

It will be expedient, it will be more costly than it needed to be. It probably will not be the best choices available. But it's possible that we'll get an early warning or a leading indicator and not just ride blindly into widespread degradation of the system.

The CHAIRMAN. Senator Ford.

Senator FORD. There's one indicator probably I think that is there, or here where we're talking, and we're caught right in the middle of it. When I say "we I'm talking about the elected officials, because I think without exception every professional poll will show one of the No. 1 items is utility rate costs.

Utilities are big and the general public can beat up on them pretty good and maybe get away with it. Somehow I wonder if that's what ought to be done. Under the present circumstances, the utility cannot win. I say the present circumstances: A plant either is built and there's no need for it or they haven't built and there is a need for it, and so they're in a catch-22, and there's no way for a generating facility to win.

If they are very close, very close with a surplus, they may be big winners. But what I've seen is that there's no closeness.

One other thing that bothers me, and I'd like to ask this just as a general question: If you were a utility executive today, would you build a major base load plant, 1,200 megawatts plus, unless you were ordered to do so by a regulatory body? The answer could just be yes or no and not much elaboration.

Dr. Farney.

Dr. FARNEY. I think not.

Senator FORD. You think not? You would not build one unless you were ordered.

Mr. Smith.

Mr. SMITH. For the majority of PUC jurisdictions, the answer would be no, I would not.

Senator FORD. Dr. French.

Dr. FRENCH. Agreed. With some minor exceptions, I think most regions would have to say no, you would not build that. You'd be hurting your stockholders.

Dr. HOGAN. I agree with my colleagues.

Senator FORD. Dan.

Dr. DREYFUS. I agree.

Senator FORD. Why? [Laughter.]

Dr. FARNEY. There are few service areas where the balance sheet is healthy enough to support a big construction effort. In the examples that jump to mind, they don't have plans to build plant either, so they've become almost irrelevant to this discussion.

I think that in those service areas where there's likely to be load growth, there has been load growth in the recent path. They've had to build. They may have had bad experiences in trying to build, and their balance sheets are stretched pretty thin.

Senator FORD. Mr. Smith.

Mr. SMITH. Well, it's an 8- to 15-year obstacle course, and if I finally complete—with variable hurdles, sometimes only told how high they are after I've gone over them. And if I finally make it through that course, I may or may not get paid for what I've invested in.

Senator FORD. Dr. French.

Dr. FRENCH. I'd say there's two reasons there. One of them is the cost of borrowing the funds or obtaining the funds to build new plant; and the other is the returns from building that plant, the revenues. And on both ends there are problems for utilities right now.

On the cost side, we're talking about regulatory delays, increasing interest costs, and high real interest rates related to Federal deficits, increasing the cost of borrowing funds for utilities. And on the revenue side, we're talking about the rate suppression issue and the potential for not having their borrowing cost translated into revenues further down the line.

Senator FORD. Dr. Hogan.

Dr. HOGAN. The only thing I'd add to that collection of reasons, which I endorse, is the possibility that the large plant that you suggest might not even be the most economical strategy anyhow and that there is some advantage to flexibility.

Buying smaller units which are individually more expensive per kilowatt might still be an optimal strategy because we don't know exactly what's going to happen over this very long time horizon. So having a few sequential decision points might be a better strategy, even if you didn't have all of these regulatory problems. The regulatory problems compound it, so you have to educate your commission and look for more flexible strategies at the same time.

Senator FORD. Dan.

Dr. DREYFUS. Well, I think a utility manager has a set of established responsibilities to the board of directors and the stockholders, and if you look at the results on the financial statements of any kind of a big investment like that today, all the indicators get worse. The stockholders' position gets worse, the strength of the company from the standpoint of revenues, profits, debt-equity ratio and everything gets worse.

There is no reward for getting into it. I would agree, though, with Dr. Hogan, there are some fallbacks that need to be considered in the planning system.

Senator FORD. Two quick questions, Mr. Chairman. One is that, all of you talked about high interest rates. I thought interest rates were down. They were double digit 4 or 5 years ago and now they're down to close to 11 or 12 percent from 21 percent, I thought.

Dr. DREYFUS. I think everybody said real interest rates, which is a question of the spread between inflation and the interest rate.

Senator FORD. Oh, so it's real interest rates, just not what we see out there. The historical difference is about four points above inflation and this is about eight points above inflation. So the real interest rate is what we want to get on the table then, today.

You talk about regional problems. Is there any way that we could look at the regions and encourage building and in other places discourage it? How do you get into—I think we got—we're meddling in too many people's business now. How do we work out a regional problem?

All of you I think talked about regional problems. Mr. Smith, you're the only one I can relate to out there. The rest of them are doctors. [Laughter.]

Mr. SMITH. Well, we approach the forecasting process by looking at individual regions. The particular regions that we use happen to be the census regions because our forecasts basically start with economic information to drive our energy forecasts.

The more appropriate regions are probably the reliability council regions, because here a certain amount of cooperation and pooling of power takes place, sometimes formal pool dispatch and sometimes less formal.

I'm not sure that I completely understand your question.

Senator FORD. Well, you talked about the regions. If we look at the total capacity it may be one thing, but then you begin to look at regions and they may have a different or individual problem that isn't necessarily the broad view. We've got enough to do it, but we find pockets where we're short or over.

And you were talking about certain regions, and I think at least the regional concept was that we needed to look at that rather than the total picture.

Mr. SMITH. Right. Well, we look at regions as an aid in our forecasting to see where problems might exist. In terms of changing policy or of the need for different regional approaches to looking at the problems, I would say that the problem is already being addressed on a very regional basis. There's the Northeast Power Pool and what have you.

The individual utilities in a region do cooperate in varying degrees. And not only that, there are interties that exist between one region and another. So there is a great deal of regional cooperation.

When I talk about the need for changes in the regulatory framework, I think the last thing that I'd like to suggest is yet another formalized layer of regulation and perhaps coordination, such as more emphasis at the regional level. So the regional planning and coordination is already taking place. The regulatory problems lie elsewhere.

Senator FORD. Dr. Dreyfus, you may have made it in your statement. I'm trying to recall, and if you're not the one, whoever stated it talked about the problems in New York and New York could lean more on Canadian source of energy. I find that most of the Northeast is beginning to look to Canada for energy sources. I think Vermont last year signed a 20-year contract with a Canadian power producer, a mix of hydro and nuclear, whatever.

Are we losing our energy capacity to Canada in some areas of the country?

Dr. DREYFUS. That comment wasn't mine, but it's pretty clear we're building a lot of Canadian powerplants. I defer to——

Senator FORD. Dr. French.

Dr. FRENCH. I think the issues involved here are: one, that it can indeed be economical to purchase power between regions, and that may well be one of the ways that we address the issue of surpluses in some regions vis-a-vis what was expected in terms of demand and deficits in others.

However, what's involved in here is the potential for higher cost of electricity. In particular in terms of New York and New England's imports from Canada, if those are the regions where they underestimate load growth there is potential for demanding more electricity imports from Canada.

And while the cost of hydro from Canada and nuclear from Canada can be relatively low for Canada, there is the potential that national energy policy for Canada may involve setting rates that would be higher than investments in base load in the United States, for example in coal.

Senator FORD. Dr. French, what would happen then if Canada starts developing a shortage and they say, hey, we want to keep it within our borders? What happens to those who have contracted with Vermont, Vermont, maybe New York upstate, and others? Does that create a problem?

Dr. FRENCH. Well, I think in terms of the cost, we're talking yet another way——

Senator FORD. Well, that could be a shortage. That could be a shortage, is what I'm talking about. I don't know whether there will be a shortage or not. Maybe there is a clause in the contract, but surely if Canadian energy begins to have a shortfall they're going to be looking inwardly rather than to ship it across their borders.

Dr. FRENCH. I think there is potential, if there is bad planning on the part of electric utilities, I would say drastically bad planning on the part of electric utilities, for shortages to arise. We don't anticipate drastically bad planning by electric utilities.

What we do see is the lead times getting short enough that one has to turn to higher cost alternatives. Purchased power is one. If you're saying that's not an option for some reason in terms of Canadian power, then we'd be talking about the cost of reverting to higher cost oil or gas-fired generation.

And unless the load planning is poor enough—and we don't think it will be that poor—to not foresee the problem say 3 years down the line, then we'd be talking simply about the use of higher cost generation.

Senator FORD. I think that's my time, Mr. Chairman. I thank you.

I want to get into—I want to ask Dr. Farney a particular question. I'll give it to him in writing. You talk about the different marketing strategies in the future. I'd like for you to elaborate on that question.

The Chairman. Senator Evans.

Senator EVANS. Thank you, Mr. Chairman.

I think I was pretty interested in the individual statements until I heard the question of the chairman and each one of you respond to it. And frankly, I was a little disappointed. It sounds to me like we're marching confidently forward into the future looking backward.

Isn't there a better alternative than speaking of brownouts, blackouts, or the alternative of the 20- to 25-percent margin? Dr. Farney, you mentioned the higher cost for insufficiency and the lower cost for extra capacity. But isn't that how we have planned for many years, with the pleasure of that knowledge that the marginal cost of new capacity for many, many years was lower than the average cost of capacity?

And sure, you could afford a large margin, because you were better off. You could lower the cost of electricity, you could generate more demand, you could sell more, you had a bigger base on which to get a rate of return. That was easy to have a large margin.

But aren't we now at a point where maybe that relationship has changed or is changing? There obviously are pretty high costs of extra capacity. Otherwise these utilities wouldn't be at a point now where they are stretched out financially. If it was easy or if there was a lower cost for excess capacity, wouldn't we continue to have excess capacity?

Let me start with Dr. Farney.

Dr. FARNEY. If I understood——

Senator EVANS. Wouldn't it be inconsistent to say that the utilities are stretched out financially, that they are not able to move, but that there's still a lower cost for extra capacity and a higher cost for insufficiency, but they're headed pellmell to insufficiency?

Dr. FARNEY. If I understood your question, Senator, I agree with you. I believe that the problem is one which arises in small incremental steps. I don't believe there will be any catastrophe. I believe there will be utilities who, even though this panel of experts would disagree with the wisdom of the choice, will build powerplants. They'll probably not earn what would be considered a fair rate of return on that investment.

The issue as I see it is, as we build, as our utility systems grow, will we build in the 20- or 25-percent reserve margin that we had historically? I think that if we look at recent history we can see a pattern developing which leads me to argue that we will not. That the standards for system reliability will be lowered in the same de facto manner that they have been lowered over the last 10 or 15 years.

Senator EVANS. Do you think it necessarily will significantly lower system reliability if we can manage more closely to the margin? Does it really mean that—statistically, obviously, if you go from a 25-percent margin to a 10-percent margin or some other figure, statistically it's less reliable, but in reality is it?

Dr. FARNEY. That's exactly my point. It may be the case that we'll make the compromise on system reliability and the end user will not notice a difference in the quality of service, although the generating dispatching algorithms used by the utilities would measure it. That's another issue which I'm not prepared to answer today. I think it's a very important issue.

Senator EVANS. Dr. Hogan, you mentioned that the option may be for a smaller but somewhat more expensive alternative. Does that necessarily always end up being the case?

It seems to me one of the major costs of new production is the risk of time, and there has been an inordinate extension of time for nuclear and coal plants which has created the risk that has caused many utilities to just shy away, understandably, from that kind of investment; and the reason of course being that they cannot predict with any precision ten years ahead of time what the needs will be.

Does smaller necessarily mean more expensive? Or does smaller maybe mean more prudent, and with at least an even chance that it will be less expensive by not building a great overcapacity that you can't sell?

Dr. **Hogan**. I agree with you, Senator. The point I was trying to make was that if you knew exactly when you were going to need it and how much you were going to need and you didn't have the uncertainty and you calculated the cost based on that calculation, you might say: Well, the big, most efficient, perfectly designed for this time and this fuel is the cheapest way to go, but faced with the uncertainty before the fact, it may turn out that on average the best thing to do is smaller, but individually they might look like slightly more expensive units.

I might also add that in the context of your earlier concern about the agreement on the part of the committee here, I don't think any of my colleagues, although they can speak for themselves, would take the view that you necessarily have to choose between efficiency and conservation and load management and more capacity. It's not a dichotomy in that you have one or the other.

In fact, there's a mix of all of those things, and consistent certainly with my own analysis is the view that you'll see a great deal of continued conservation, but that in itself is not going to completely eliminate the need for new capacity to back out more expensive generation or to meet the future demand.

So it's a combination that you're looking for and it's a combination, and a decision made today facing the kind of uncertainties you've been describing.

Senator **Evans**. Well, yes. It seems to me that that is the case, just as you don't have to make the decision as between the two sort of Draconian points of 25 percent oversupply or a blackout, that there's got to be and I'm confident there will be—we will steer somewhat between those two sharp rocks, and I don't think we're likely to go aground.

To what degree—I don't know who can best answer this. To what degree—to those of you who are in charge of some of our national econometric models—to what degree do your models really take into account, or can they take into account, the potential of interregional sales and the potential—I'm thinking now particularly of the west coast and the very real potential which I think exists for interregional capacity or transmission capacity increases, which could allow the working together of two systems which ought to be able to work in great harmony, systems which have a summertime peak in the Southwest and a wintertime peak in the Northwest, a system which in the Northwest isn't even peak demand constrained, we're more energy than capacity constrained.

I believe there is an opportunity, for instance, to utilize what may become standby combustion turbines in the Southwest with increased sales of power from the Northwest to help firm up what now is not firm power from our hydro system in the Northwest. I can foresee the equivalent of a couple of nuclear plants maybe, without building anything other than transmission lines and a better management between the two regions.

Now, does any of that really get caught up in your econometric models? Or can't you detect those things?

Dr. **French**. I think our models account for the need for such investments in laying of transmission lines between regions. That is, we'll come up with forecasts for electricity demand by region and then look at the projections of electric utilities within each region for capacity expansion within that region.

So I think you're right, Senator, in the sense that we're looking for a substantially increased role for interregional transmission and purchased power in the coming years as a relatively best alternative. There are a couple of caveats there, however. Those caveats are that it's expensive to lay new transmission line and that there are regulatory delays in terms of getting right of way for new transmission line. These do increase costs, but certainly there's no question that we're looking for increased interregional transmission in the future.

Senator EVANS. Well, isn't that a decision to be made if that choice is cheaper than building independent central power stations or whatever the alternative is, then it's a prudent thing to attempt to do. I don't imagine the transmission lines have any greater restraints than central power stations do now in terms of getting all the necessary permits and moving along. Both of them are horrendous.

Dr. FRENCH. Yes.

Mr. SMITH. We attempt to include transfers of power from one region to another. There are no easy modeling ways of doing this. You pretty much have to look at the specifics of the individual region and simply make judgments about existing capacities of the interties and how much power could possibly flow. And then as you look forward, you have to simply attempt to figure out when additional transfers make sense, and try to build some of these in.

But I would also add that many of these—there's been a great increase in wheeling of power, and some of these interties are already approaching capacity. So you do face some of the same construction problems and obstacles that baseload capacity does in terms of expanding. It's not a free expansion.

Senator EVANS. Yes.

The CHAIRMAN. Senator Rockefeller.

Senator ROCKEFELLER. Senator Ford had mentioned that Canadian power could or could not have a shortfall. The figures I'm looking at, in 1976 there were about 9,000 gigawatt hours imported from Canada; in 1984, suddenly we're talking about 39,000 gigawatt hours; and then some Canadian studies estimating that that could be increased from four to five times. So I don't start out with the assumption that import of Canadian power—hydroelectric, nuclear, or whatever—is a temporary phenomenon. It seems to me that it's a growing one.

But then comes the question of how does the electric utility industry in this country look upon that. It's been raised that there's the long term and the short term. The uncertainty tends to breed an instinct toward moving toward short term.

Well, if one's uncertain about public utility commission rate setting possibilities, et cetera, maybe it's safer in the long run and the short run to purchase foreign power.

To what extent do you think the increase of Canadian power imported into this country is a built-in planning factor on the part of our utilities, to the extent that it potentially undermines whatever residual instincts for building new powerplants might remain with our own American utilities? Anybody?

Dr. **Dreyfus**. I'll take a cut at it. I think what you're seeing going on today is people seizing upon the expedient way to avoid construction. You also have some pretty aggressive salesmen in Canada who are out making deals and pushing power.

I don't think that the Canadian power represents a threat in the sense of it becoming unavailable at some time in the future. I do think that the pricing of Canadian power is going to have a future something like the history of pricing of Canadian gas. It'll be high priced when you need it the most, and that's built into that system. The other thing of course is that the decision to do anything to escape from those contracts is a 10-year leadtime decision, or at least a 5- or 6-year leadtime decision, and that means that you can pay the price quite a long time before you get another chance to bet.

Senator **Rockefeller**. But provided there's not a decrease in the availability of Canadian power, that immediate purchase capacity is always going to be there, isn't it?

Dr. **Dreyfus**. Well, now there is of course a history that the Canadians at one time did not sell us gas that we wanted when they had a 22, as I recall, to 1 reserve ratio. So I don't know that I can conclusively say that could never happen.

From what I know about Canadian energy demand, I can't conceive of a situation in which they would need it all at home. And it becomes a lot less logical decision to shut in a hydro powerplant especially, or any powerplant investment, than to shut in a gas well. So my guess is you're not looking at interruptions. You're looking at changing pricing which will reflect the demand situation.

Hence, about the time you're buying a lot of imported oil will be about the time that Canadian power becomes more expensive.

Senator **Rockefeller**. Is it any more difficult for a grid system, a power company within a grid system in this country, to purchase power from the Canadians than it is from another grid system within our own country? Are there any regulations or problems to go with that?

Dr. **Dreyfus**. It's an import, which involves another agency as I recall, but I'm not clear on what the hoops are. I believe there are additional steps in approving it.

Senator **Rockefeller**. What are the additional steps that need to be taken? Can somebody else answer that?

Dr. **Dreyfus**. I'm sure you have somebody who does know that in the room.

Senator **Rockefeller**. I mean, can I go and purchase power if I'm a utility from Canada just as easily as I can from the Mid-Atlantic or the Far West, or the South Atlantic?

Dr. **French**. I think part of the issue is transmission lines in place; that in principle the power is there from Canada, but there is a cost to laying transmission lines, and this would have to be planned in advance. Perhaps not as far in advance as for new coal-fired capacity, but certainly some planning is called for.

Senator **Rockefeller**. Do you think, Dr. French, that the availability—the apparently available and increasingly available nature of the Canadian power is something that American utilities have built into their own building plans, or lack thereof?

Dr. **French.** I think if you look at the publication of the North American Electric Reliability Council last year regarding the building plans, and regarding the plans of various utilities around the country to meet their expected load increase, yes, very definitely there are increases built into New York-New England, is my understanding.

One of the issues for New York is, suppose demand increases even greater than these utilities have been planning for? What do they do in terms of dealing with Canada at that point? Will the transmission lines be expanded in time? What will the rates on that electricity be vis-a-vis other options?

Senator **Rockefeller.** I say that, Mr. Chairman, only because I view this whole—and I understand the international marketplace and all the rest of it, but this question of imported Canadian power has a particularly devastating effect upon the part of the country that I come from. Obviously it's a direct effect—we've been shipping coal up to the Northeast, and now we find we're competing against Canadian power. And a less of a willingness on the part of utilities, as has been amplified by the panel, to go ahead and build. And in fact, something of a lessening of an instinct on the part of those utilities still using oil, imported or otherwise, to convert to the use of coal.

In fact, I would like, as my final question, Mr. Chairman, to ask the panel: I find it extraordinary when Orange & Rockland Utilities, just outside of New York, north of New York, converted from imported oil, I think from Venezuela, to coal, they did battle for several years with EPA and they had a new air modeling system which showed it to be a very good and wise thing for them to do, but it was kind of stunning. There had been no coal conversions—conversions to coal in that part of the country—that is, the Northeast—except for the Breyton Point New England Electric System conversion which was spectacular, but that involved a very high sulfur oil to lower sulfur American coal, and then Orange & Rockland. But they did convert. It did take place recently. They did think it was in their interest. They did figure it was going to save their consumers a lot of money.

Why has there not been more of it—coal conversion, that is, oil to coal, in your judgment?

Dr. **Dreyfus.** Senator, it is a highly capital intensive conversion, although it's not to the degree of a new powerplant. We currently have an expectation in the country, correct or not, that oil prices are going to go down in the next 20 years, during which time most of those facilities will be retired. So it's hardly a great pressure in the future in some sense.

Most of them are not running as baseload plants; they're running at limited load factors against purchased power from other systems. So that it's only if you run up against this reserve short fall that you're really going to be buying a lot of oil. There's 1 million to 2 million barrels increase in oil that could be involved there.

And the other thing is that those converted, as I recall, had extraordinarily good cooperation from their utility commissions and from local government. Not everyone has gotten the same degree of——

Senator ROCKEFELLER. Do you think that was the key? Because that certainly was the case with Orange and Rockland.

Dr. DREYFUS. It was relatively unique. The direct involvement of the public bodies in this business up there was quite unique.

Senator ROCKEFELLER. Thank you, Mr. Chairman.

The CHAIRMAN. Thank you very much, Senator. And, gentlemen, thank you very much for your testimony this morning and your response to questions. Further questions will be submitted to each of you in writing for a response to the record, and we would appreciate that response. Thank you all very much.

We will next hear from a panel of Mr. Sherwood Smith, John S. Kaslow, Mr. W. S. White, Jr., A. William Dahlberg, and Mr. Keith L. Turley.

While those panel members are taking their seats, I might announce that it will be our intention to complete the testimony of this panel and take a brief recess for lunch, and reconvene to hear the others.

STATEMENT OF SHERWOOD H. SMITH, JR., CHAIRMAN, EDISON ELECTRIC INSTITUTE

Mr. SMITH. Good morning, Mr. Chairman.

I am Sherwood H. Smith, Jr., chairman and president of Carolina Power & Light Co., and also chairman of the Edison Electric Institute. With me today are other executives who are appearing for our electric utility industry.

Beginning on my immediate right is Mr. John S. Kaslow, president of New England Power Co., and executive vice president of New England Electric System. Then, Mr. W. S. White, Jr., chairman and chief executive officer of the American Electric Power Co. Then, Mr. William Dahlberg, president and chief executive officer of Southern Company Services. Next to Mr. Dahlberg is Mr. Keith Turley, chairman and chief executive officer of Arizona Public Service.

As has been described in great detail by the previous panel, the electric utility industry's views here are—I might add, parenthetically—I think are very much in accord with most of what the previous panel said I think very clearly and very articulately. Unlike total energy consumption in this country since 1973, we've seen the consumption of electricity continue to grow significantly.

During 1984, for example, electric sales in the United States were 5.6 percent higher than the preceding year. Sales to industrial customers were up 7.3 percent due to vigorous economic growth and economic recovery in some areas of the country. Last year we also saw a record weekly electric output figure in August for that period of 54.1 billion kilowatt hours. That record, however, was soon surpassed this past January of 1985 by a 7-day total of 54.7 billion kilowatt hours, this being the first time since 1968 that a winter output week surpassed the preceding summer output.

This record was due of course to several conditions. One of those was extreme weather conditions. The continued economic growth and growth in electric consumption have a great deal to do with it, also. We think that the more significant point is not why there might have been a record consumption at that particular week this past January; it's the point fundamentally that our systems must be prepared to meet large increases in electric demand in the future, and we're very concerned about our ability to do that.

The precise and exact amount of future growth in electricity of course remains uncertain and controversial and can be subject to considerable debate. But our electric utility industry has adopted what might be described as a mid-range forecast. That is, a forecast between the levels of 1 percent and 4 precent, which had been mentioned earlier.

The North American Electric Reliability Council, NERC, is projecting growth in kilowatt-hour requirements of 2.4 percent, and a peak demand growth of 2.2 percent from 1985 to 1994. Over the same period, however, capacity additions are scheduled to average only 1.65 percent per year or less. These additions result from the completion of existing construction programs, and electric utilities have virtually ceased ordering new capacity of any kind today.

In a very difficult planning environment, electric utilities are adopting a broad mix of options in an effort to assure a proper balance between supply and demand in the future. In addition to maintaining our construction program to the best of our ability, the industry is pursuing new generating technologies which are smaller, modular, and cleaner environmentally.

We are implementing mutually beneficial demand-side management programs. We are purchasing power from third-party sources, and we are strengthening our transmission systems. It is our hope that these strategies, plus the level of planned additions, may be sufficient to satisfy our basic needs until sometime in the early 1990's.

However, we realize that this will not be enough to replace those oil and natural gas facilities that may become uneconomical. To do those replacements, the Electric Power Research Institute has estimated utilities will require something on the order of 36 gigawatts over and above what is currently planned.

Also, if we're forced to contend with delays or cancellations of those plants under construction today, or if economic growth and corresponding electric growth are higher, even more new baseload capacity now unplanned will be needed tomorrow. This new baseload capacity should come from coal and nuclear power.

Electric utilities are facing crucial decisions in planning for an uncertain future. I believe Dr. Dreyfus at the conclusion of his testimony a few minutes ago described the situation as a crisis in planning, and we would certainly subscribe to that statement.

There will be new capacity needed to meet economic growth. There will be new capacity needed to take care of the retirements and obsolescence of some of our existing plants. Just like any industrial facility, electric plants age; they become less efficient, less available, more expensive to operate, and eventually they must be retired.

As I said earlier, in some cases new capacity is needed to replace capacity now dependent upon high cost oil and gas, especially imported oil. I might add that since 1973 and the OPEC oil embargo, the electric utilities have cut oil consumption by over 60 percent. Improved availability and prices for these fuels has mitigated what was in recent years intense pressure to reduce their use; yet, most energy analysts agree that we should continue to work towards becoming less dependent on these insecure, high cost, and often foreign-supplied fuels.

Fundamentally, we believe that what is at issue here before this committee should not be the precise accuracy of any particular forecast. We assure you that we will continue to apply the most rigorous professional forecasting techniques available. We will continue to plan, as best we can in a world of risk and uncertainty; but the heart of the problem is that political and economic incentives warrant avoiding new capacity investment all together, regardless of exact level and timing of the need for this new capacity.

Utilities today face significant impediments to undertaking new investment, whether it is to build a generating plant, or to strengthen existing transmission systems. A company today, for example, who plans to build a new generating plant may well discover that its earnings on this new investment would fall below the cost of the capital to finance the investment. Construction work in progress is not uniformly allowed in the rate base to enable lower cost financing and construction.

Other disincentives come from regulatory penalties found in some recent state rate decisions disallowing portions of new plant construction from the rate base. In some case, the treatment of investment in cancelled plants has been particularly harsh. Even where it was in the consumers' interests for the plant to be started, and later also in the consumers' interests for the plant to be cancelled.

A recent EEI survey found that in 1983 not a single commission decision on cancelled plants provided for a full recovery of the lost investment cost.

There is another growing perception which in some areas of our country is threatening to become a presumption rather than a perception. That is, that when things go right, the ratepayers benefit; but when things go wrong, the investors must take the loss. An officer of one large electric utility has captured the mood of this in his comment on what has become known as "prudency,"or that is, a commission investigation to determine whether or not the investment or the total amount of investment was "prudent or not prudent."

He said: The industry is judged by "prudency standards which require foresight to be at least as accurate as hindsight."

The risks and uncertainties arise not only from specific state rate actions, but also from the ever changing maze of Federal laws and regulations. There are generating plants, as described a few moments ago, which were originally built to be fueled by coal, which were converted to oil to satisfy our environmental regulations, and now some have been reconverted to coal to satisfy fuel-use restrictions.

Again, rules and regulations regarding the use of coal are now under debate. In addition, tax laws provide another example. It is possible, depending upon the decision of Congress this year or early next year, that in the space of 5 years our electric utility industry will have been subject to four fundamentally different tax programs. Such changes can be paralyzing for an industry with long lead times that are very heavily capital intensive.

These are just several of many examples of how changing rules and regulations obscure any clear idea for planning for the distribution of risks and costs of constructing new facilities, or the cost of operating those facilities, and the extent of financing required for those facilities.

Other regulatory-induced impediments to adding capacity include the threat of still higher prices for coal transportation by rail, the extensive delays associated with permits and licensing, difficulties in siting transmission facilities, and incomplete consideration of the cost of construction work in progress.

Nuclear regulation provides a vivid illustration of most of these problems. Regulatory requirements applicable to the new nuclear units began to increase significantly in the early 1970's. Following the accident at Three Mile Island in 1979, the flow of new requirements became a literal flood. By the early 1980's, the Nuclear Regulatory Commission had issued 2,000 regulatory guides, letters, bulletins, orders, notices, and standards governing the U.S. nuclear industry. Many of the new requirements were necessary and appropriate, but many others made no significant contribution to safety, or failed to provide benefits commensurate with their cost.

Needless to say, the impact on cost and construction time tables of nuclear plants was dramatic and very harsh. This experience, as well as suggestions for change, was recently documented in the report of the Edison Electric Institute on nuclear power, which was published in February of this year. And, Mr. Chairman, if I may, I would like to offer this report as an additional exhibit to my testimony.

The CHAIRMAN. Thank you. It will be placed in the file of the committee.

Mr. SMITH. Obviously, unless there are substantial changes and improvements in the way in which nuclear powerplants are required to be licensed, constructed, and operated, you will not see any nuclear plants added in the future; nor will it be possible to operate those in service in an efficient, economical, as well as a safe manner.

The danger that all of these legal, regulatory, and financial obstacles create is that the utility industry may be forced to cite costly, short-term options where available over what would otherwise be more cost effective long-term options. Specifically, less capital intensive oil and gas turbines with shorter leadtimes may be installed where possible to do so to avert a shortage.

Oil consumption certainly would rise. Customer costs would be unnecessarily high, and the vulnerability to fuel interruptions would be heightened.

What is at risk, if indeed a shortage comes to pass, a subject that was discussed briefly by the preceding panel, first, it is undeniable that the economic costs could be very large. A number of specific studies on industrial outage costs have been conducted. For example, a 15-minute outage to a chlor-alkali plant was estimated to cost $18,000. The same outage to a pulp and paper plant was estimated to cost $55,000 for an hour.

Also, these studies all indicate that a large portion of the total costs are incurred at the onset of even the briefest outage. An Electric Power Research Institute review found that outage costs ranging from $1.93 to $11 on a kilowatt hour basis would far exceed the average cost of only 6¼ cents per kilowatt hour delivered in 1984. Not only would the direct cost be significant, but the impact on productivity and international competitiveness would have longstanding effect on the economy.

Second, of course, the political cost could also be very large. It is likely that a political solution to the problem might impose even more economic costs. Our system is particularly inept, I would submit, in allocating shortages. The gasoline lines and natural gas curtailments of the 1970's led to a maze of Government allocation rights and priority listings, most if not all of which proved perhaps to have been the wrong thing to do.

There do remain a number of steps which utilities, consumers, and Government can take in an effort to forestall a serious problem. This problem will remain a very real possibility, however. Without question, continuing impediments to investment will lead to electric price increases later, which will be higher than necessary, which by themselves will create perhaps somewhat of a drag on the economy.

Perhaps more serious problems can be averted. What can the Government do? The contribution which Government can make to resolution of these problems is both direct and diffused. At the Federal level, the stabilization of the tax system with financing mechanisms intact should be a high priority. This includes not only capital formation provisions of the Tax Code, but also the option of assuring that all generations of customers receive equitable treatment regarding tax expenses and rates.

This allows regulated industry to receive the same benefits from capital formation provisions as afforded to unregulated companies consistent with overall economic policy.

Second, stability in environmental and nuclear regulations is mandatory. Full consideration must be given to both the costs and risks incurred in the pursuit of environmental benefits which we all desire. The regulation of nuclear power must be substantially streamlined and improved. Individual utilities operating hydroelectric facilities should not face the threat of loss of these facilities that impact on their planning through changes in a relicensing policy.

Also, utilities should be able to engage in small hydro and cogeneration projects on a basis equal with all others, a comment made also by Dr. Dreyfus earlier. Further, Congress can directly contribute to the resolution of the supply and adequacy problem by enacting legislation to fund a clean coal technology reserve.

To address the problem of nuclear power, we recommend a broad agenda of reform. While the industry should and must continue on its own to improve in all aspects of constructing and operating nuclear powerplants, there are some specific measures which fall under the jurisdiction of Government. Specifically, we recommend changes in Federal law and regulation so that standard plant designs are approved, and thereby plants promptly licensed; that plant sites are approved in advance of construction application; that a single-stage licensing system be adopted for construction and operation; that the existing legislation provide for a safe, permanent disposal of nuclear waste, be fully implemented; that the

Price-Anderson Act be extended with the continuation of provisions for indemnifying and protecting the public as well as a cap on total potential liability.

Most importantly, there must be improvement in the nuclear regulatory process at the NRC level. At the State level, regulatory and legislative authority should acknowledge the ongoing, continuous long-term requirements for increased electricity supplies. Regulators should also work to improve the economic signals which bear on company and customer decisions.

This means recognizing the economic value of the capital stock in our electric utilities, and allowing electric prices to reflect the variability of cost, both of which are increasingly important in a competitive environment.

In conclusion, Government, because of its powers, is central to the issue of how long-term supply adequacy will be resolved. We do have a problem. As I said, it is accurately described as a crisis in planning, but also it is a crisis in acting on plans once made. We are on a collision course between growing demand and our ability to meet that demand. Positive Government actions are certainly indicated.

Very importantly, we believe the Federal Government should rearticulate the goals of national energy policy, focusing on the adequacy of supply, relying primarily on domestic fuels. In the meantime, the electric utility industry is focusing its planning on this critical timeframe.

We urge Congress to participate with us and our customers to ensure that the worst does not come to pass, while there is still time to prevent it.

Thank you, Mr. Chairman, and I will be available for questioning after the panel.

[The prepared statement of Mr. Smith follows:]

STATEMENT
# of the
Edison Electric Institute

Before the

UNITED STATES SENATE
COMMITTEE ON
ENERGY AND NATURAL RESOURCES

Presented by:
Sherwood H. Smith, Jr.
Chairman, Edison Electric Institute

July 23, 1985

Good morning, Mr. Chairman. I am Sherwood H. Smith, Jr., Chairman and President of Carolina Power and Light Company, and Chairman of the Edison Electric Institute. With me today are other executives appearing for the electric utility industry:

A. William Dahlberg, President and CEO of Southern Company Services, Inc.;

John F. Kaslow, President of New England Power Company, and Executive Vice President and CEO, New England Electric System;

Keith L. Turley, Chairman and CEO of Arizona Public Service; and

W.S. White, Jr., Chairman and CEO of American Electric Power Company.

We welcome the opportunity to present our views on the outlook for electricity supply adequacy in the years ahead. Today, the current situation is one of generally adequate electricity supplies in most parts of the country. This fact coupled with the difficult circumstances of a handful of companies struggling to complete longstanding construction programs tends to obscure the continued growth in electricity consumption and the need to plan for adequate supplies in the future. A combination of forces has, in the aggregate, presented a threat to our ability to provide adequate electric supplies as consumption continues to grow. The causes of this situation are many and the potential consequences are far reaching.

Unlike total energy consumption, electricity consumption has grown significantly since the oil embargo of 1973. While total energy consumption declined one percent since that time, electricity consumption has grown 33 percent. The trends underlying these numbers are expected to continue. Electricity will continue to account for a growing share of total energy consumption.

This growth in electricity usage is not a peculiarly American occurrence. Recent research by the World Energy Conference into the economies of 23 major western nations shows that in the decade of the 1970s and into the 1980s, total energy consumption rose by only one percent while electricity consumption rose by 33 percent. At the same time, major progress has been achieved in the efficiency of energy use. In fact, our trading partners with the higher economic growth rates (Japan, West Germany, and France) and with the greatest gains in energy efficiency have achieved improved economic output with emphasis on applications of electrical technology. The United States, as well, has shown a 25 percent reduction in total energy use per unit of GNP while electricity consumption, however, grew by 33 percent.

During 1984 electricity sales in the United States were 5.6 percent higher than in the preceding year. Sales to industrial customers were up 7.3 percent due to vigorous economic growth. Last year included a record weekly electric output figure in August of 54.1 billion kilowatt-hours. That record was surpassed this January by a seven-day total of 54.7 billion kilowatt-hours--the first time since 1968 that a winter output week surpassed a preceding summer week record. This record output was largely attributable to extreme weather conditions, but continued economic growth also had significant responsibility for it. The most significant point is not why there was record consumption; this point is simply that a record amount of electricity was needed, and more may be needed in the future.

The precise, exact amount of future growth of electricity demand, of course, remains uncertain and controversial. However, virtually all forecasters expect electricity demand to continue to grow. Long-run estimates of electricity growth generally range from 1.0 to 4.0 percent annually accompanied by an average annual growth rate of GNP in the 2.5 to 3.5 percent range. Regional growth rates in peak demand are predicted to vary from about 1.2 percent in the Middle Atlantic area to 3.6 percent in the South Central area. The electric utility industry, as reported by the North American Electric Reliability Council (NERC), is projecting growth in kilowatt-hour requirements of 2.4 percent and in peak demand of 2.2 percent from 1985 to 1994. Over the same period capacity additions are scheduled to average 1.65 percent per year, or less. These additions result from completion of existing construction programs. American electric utilities have virtually ceased ordering new generating capacity of any kind.

The industry is now in a planning environment of slower growth, and rising costs. Some of the strategic implications of this are tendencies to (1) build smaller scale relative to the past, (2) consider renovating existing facilities, (3) build only small increments of capacity which better track demand growth and fluctuations ignoring the economies of scale, and (4) select technologies with a higher ratio of variable to total costs.

In this planning environment, utilities are adopting a broad mix of options in an effort to assure a proper balance between supply and demand in the future. In addition to maintaining its construction program to the best of its ability, the industry is pursuing new generating technologies which are smaller, modular, and cleaner environmentally; implementing mutually beneficial demand-side management programs; purchasing power from third party sources; and, strengthening transmission systems.

We hope, and now expect, that these strategies plus the level of planned additions may be enough to satisfy our basic needs until some time in the early to mid-1990s. However, we also expect that this will not be enough to replace those oil and natural gas facilities which are uneconomical. To do that, the Electric Power Research Institute (EPRI) has estimated that utilities will require something on the order of 36 gigawatts over and above what is currently planned. Also, if we are forced to contend with delays or cancellations of plants on order today, or if economic growth and corresponding electric growth are higher, even more new base load capacity now unplanned will be needed tomorrow. This should come from coal and nuclear power.

The simple arithmetic associated with these numbers yields some important results. First, considering the uncertainty of future growth, a 2.0 percent difference in average annual growth creates a 150,000 megawatt difference in new capacity requirements in 2000. This seemingly modest range of uncertainty is equivalent to three large baseload generating plants in each and every state. Second, even the modest growth rates reported by NERC mean a

27 percent increase in electricity consumption by 1994. Third, given the projected growth rate and the currently planned capacity additions, sometime in the early to mid-1990s capacity will become inadequate unless additional steps are taken. Let me emphasize that this assumes that all current construction programs are maintained for both new generating units and transmission facilities. Unfortunately, some of the capacity now under construction or planned may have to be cancelled or deferred.

Plainly stated, capacity is being added more slowly than demand is growing. Are we, therefore, promising a shortage? No, we are not, although it is a distinct possibility. If growth is higher than anticipated, due either to rapid economic growth or extreme weather, then we may indeed face serious problems. Evidence is mounting in some regions that the probability of a regional shortage seems to be growing.

Electric utilities are now facing crucial decisions in planning for the future. There should be little doubt that new capacity is needed for the 1990s and beyond. First, new capacity is needed to support continued growth in population and the economy. Second, new capacity is also needed to provide for aging and retirements of generating plants. Just like any industrial facility, plants age, become less efficient, less available, more expensive, and eventually must be retired. Third, in some cases new capacity is also needed in order to reduce dependence on high-cost oil and gas, especially imported oil. Since the 1973 oil embargo, electric utilities have cut oil consumption by over 60 percent. Improved availability and prices for these fuels has mitigated what was intense pressure to reduce their use. Yet, most energy analysts agree that we should continue to work toward becoming less dependent on these insecure or high-cost fuels. In fact, forces in place today make it likely that oil consumption will increase in the 1990s just at the time that world demand catches up with world supply creating renewed pressure on prices.

Impediments to utility investments threaten not only needed capacity additions for the future, but also can retard the strengthening of the transmission and distribution system. EEI surveys its members and prepares a projection of utility capital expenditures. The current projection indicates that 40 percent of the $26 billion planned for 1987 will be for transmission and distribution. Thus, regulatory and financial constraints may place at risk the ability to move power for reliability and economic reasons.

Fundamentally, what is at issue should not be the precise accuracy of any particular forecasts. The utility industry will continue to apply the most rigorous, professional forecasting techniques. We will continue to plan as best we can in a world of risk and uncertainty. But, the heart of the problem is that political and economic incentives warrant avoiding new capacity investment altogether, regardless of the exact level and timing of the need for this new capacity.

Utilities today are facing significant impediments to undertaking new investment, whether it is to build generating capacity or to strengthen the transmission system. A company today, for example, planning to build a new generating plant may well discover that its earnings on this new investment could fall below the cost of the capital needed to finance it. Construction-work-in-progress is not uniformly allowed in the rate base to enable lower cost financing and construction. Other disincentives come from regulatory penalties found in some recent state rate decisions disallowing portions of new plant construction from rate base.

In some cases the treatment of investment in cancelled plants has been particularly harsh, even where it was in the consumers interest for the plant to be started and later for the plant to be cancelled. A recent EEI survey found that in 1983 not a single commission decision on cancelled plants provided for a full recovery of the lost investment costs. These plants that have been cancelled were undertaken in response to conditions at the time of the construction decision usually with the full knowledge and assent of the regulatory authorities. When expected growth did not materialize or when financing became untenable, some plants were cancelled. The public perception and regulatory treatment of these cancellations serve to preclude utilities from making future commitments, the ultimate wisdom of which will be determined only in retrospect.

There is another growing perception which is threatening to become a presumption. That is, when things go right, ratepayers benefit, but when they go wrong, investors take the loss. An officer of one electric utility has captured the mood in his comment on prudency: the industry is being judged by ..."prudency standards which require foresight to be at least as accurate as hindsight."

The risks and uncertainties arise not only from specific state rate decisions, but also from the ever-changing maze of federal laws and regulations. There are generating plants which were originally built to be fueled by coal, which were converted to oil to satisfy environmental regulations. Now, some have been reconverted to coal to satisfy fuel use restrictions. Again, rules and regulations regarding the use of coal are under debate. Tax laws provide another example. In 1981, the Economic Recovery Tax Act (ERTA) was enacted with the specific objective of encouraging economic growth by stimulating savings and investment. One year later fundamental changes were made in the Tax Equity and Fiscal Responsibility Act (TEFRA) which reduced the advantages to investment. Now we are again in the midst of a debate on fundamental tax reform. We support the Administration's efforts to improve the tax system. But, mechanisms for capital formation are of fundamental importance to this industry, its customers, and the economy as a whole. This sequence of changes means that it is possible that in the space of five years we will have been subject to four fundamentally different tax regimes. Such changes can be paralyzing for an industry with a leadtime for its major facilities of 8 to 14 years and with facilities that are designed to be in place for 30 to 50 years.

These are just several of many examples of how changing rules and regulations obscure any clear idea for planning for the distribution of risks and costs of constructing new facilities, the cost of operating facilities, and the extent of financing required. Other regulatory induced impediments to adding capacity include the threat of still higher prices for coal transportation, the extensive delays associated with permits and licensing, difficulties in siting transmissions facilities, and incomplete consideration of the costs of construction-work-in-progress.

Nuclear regulation provides a vivid illustration of these problems. Regulatory requirements applicable to nuclear units began to increase significantly in the early 1970s. Following the accident at Three Mile Island in 1979, the flow of new requirements became a flood. By the early 1980s the Nuclear Regulatory Commission had issued nearly 2000 regulatory guides, letters, bulletins, orders, notices, and standards governing the U.S. nuclear industry. Many of the new requirements were necessary and appropriate, but many others made no significant contribution to safety or failed to provide benefits commensurate with their cost. Needless to say, the impact on costs and construction timetables was dramatic. This experience, as well as suggestions for change, was recently documented in the Report of The Edison Electric Institute on Nuclear Power. Unless there are substantial changes and improvements in the way in which nuclear power plants are required to be licensed, constructed, and operated, you will not see any nuclear plants added in the future, nor will it be possible to operate those now in service in an efficient, economical, as well as a safe manner.

In light of these conditions and the high costs involved, financial exposure when adding new capacity is now a daunting consideration. In some cases, the cost of adding a baseload generating plant can exceed the net worth of a company. In virtually all cases, construction is a threat to the financial integrity of a company. The financial community often downgrades the debt ratings of companies involved in large construction programs and discounts the income stream associated with funds used during construction. Without question, financial incentives work to prevent or limit construction in almost every situation.

The danger that these legal, regulatory, and financial obstacles create is that the utility industry may be forced to select costly short-term options over what would otherwise be more cost-effective, long-term options. Specifically, less capital intensive oil and gas turbines with shorter leadtimes may be installed. Oil consumption would rise, customer costs would be unnecessarily high, and vulnerability to fuel interruptions would be heightened.

To summarize, extrapolating the current supply-demand ratio into the future and thereby concluding that no new capacity is now needed to be planned and impediments removed for its construction, ignores the dynamics of the electricity market, the planning horizon of the industry, and could well be costly to consumers and to the economy as a whole. For policy purposes, it really should not matter what the exact shortfall is or where the shortage may first appear, but that forces are in place to make it happen somewhere, sometime.

What is at risk if indeed a shortage comes to pass? First, the economic costs would be large. A number of specific studies of industrial outage costs have been conducted. For example, a fifteen minute outage to a chlor-alkali plant was estimated to cost $18,000. The same outage to a pulp and paper plant was estimated at $55,000. Also, these studies all indicate that a large portion of the total costs are incurred at the onset of even the briefest outage. An EPRI review found outage costs ranging from $1.93 to $11.00 on a kilowatt-hour basis. This far exceeds the average of 6.24 cents per kilowatt-hour delivered in 1984. Not only would the direct costs be significant, but the impact on productivity and international competitiveness would have long-lasting effects on the economy.

Second, the political costs would also be large; and, it is likely that a political solution to the problem would impose even more economic costs. Our democratic system is particularly inept at allocating shortages. The gasoline lines and natural gas curtailments of the 1970s led to a maze of government allocation rights and priority listings--most, if not all of which proved to be the wrong thing to do. Virtually every political interest in Washington and in every state capital identified unassailable arguments as to why it should receive priority treatment. Compromises seemed to keep a momentary peace in society; yet, grievous economic distortions were inflicted. There is no need to relive those experiences for electricity.

There remain a number of steps which utilities, consumers, and government can take to forestall a serious problem. It remains a very real possibility, however. Without question, impediments to investment will lead to electricity prices which are higher than necessary, which by themselves will create a drag on the economy. Perhaps more serious problems can be averted.

Industry, government, and the public each have a role to insure that potential supply difficulties do not, in fact, occur. For industry's part, companies are pursuing conservation and demand-side management as a strategic option in the face of such supply-side uncertainty. Load management, load shifting, conservation, and selective load building are being adopted to retard the need for new capacity, utilize existing equipment efficiently, improve the financial outlook of the industry, and provide greater value to the customer. New technologies are being developed which are more responsive to today's planning imperatives. This includes research and development on emerging technolcgies such as fuel cells, solar photovoltaic cells, magnetohydrodynamics, and demand-side controls. Also, work is proceeding on clean coal technologies such as fluidized bed combustion and combined-cycle coal gasification which are on the verge of commercialization. If these technologies can make it through the commercialization barrier, the benefits in the form of shorter leadtimes, smaller supply increments, modularity, domestic fuel abundance, and environmental compatibility are substantial to the utility industry and the nation. In addition, some companies are arranging or considering the purchase of capacity and energy from non-traditional sources such as Canadian imports, Mexican imports, cogenerators, and other third party suppliers. All of these, however, as stated before, will not totally replace the need for a substantial amount of new baseload coal and nuclear capacity.

The contribution which government can make to resolution of these problems is both direct and diffused. At the federal level, stabilization of the tax system with financing mechanisms intact should be a high priority. This includes not only capital formation provisions of the tax code, but also the option of assuring that all generations of customers receive equitable treatment regarding tax expenses in rates. This allows regulated industries to receive the same benefits from capital formation provisions afforded unregulated companies consistent with overall economic policy. Stability in environmental and nuclear regulations is also important. Full consideration must be given to the costs and risks incurred in pursuit of the environmental benefits which we all desire. Regulation of nuclear power must be substantially streamlined and improved. Individual utilities operating hydroelectric facilities should not face the threat of the loss of that inexpensive capacity through changes in relicensing policy. Also, utilities should be able to engage in small hydro and cogeneration projects on an equal basis with all others.

Transmission issues are another area which must be approached with great care. The transmission system is already heavily loaded for both reliability and economy purposes. This reality, the difficulty of adding transmission facilities, the physics of the system, and the reality of growing competition all argue for a carefully managed and controlled system on which we all depend every minute of every day.

Further, Congress can directly contribute to resolution of the supply adequacy problem by enacting legislation to fund a Clean Coal Technology Reserve.

To address the problem of nuclear power we recommend a broad agenda of reform. While the industry should continue to improve in all aspects of nuclear power, there are some specific measures which fall under the jurisdiction of government. Specifically, we recommend changes in Federal law and regulation so that (1) standard plant designs are approved and, thereby, plants promptly licensed; (2) plant sites are approved in advance of a construction application; (3) a single-stage licensing system be adopted for construction and operation; (4) the existing legislation to provide for the safe, permanent disposal of nuclear wastes can be fully implemented; and, (5) the Price-Anderson Act be extended with the continuation of a cap on utilities' total liability.

At the state level, regulatory and legislative authorities should acknowledge the ongoing, continuous, long-term requirement for increased electricity supplies. Regulators should also work to improve the economic signals which directly bear on company and customer decisions. This means recognizing the economic value of our capital stock and allowing prices to reflect the variability of costs, both of which are increasingly important in a competitive environment.

The role of the public, both as public citizens and consumers, is to be informed about the place of electricity in the energy picture, to understand the value of electricity to a modern industrial society, and to be knowledgeable regarding their choices in the electricity marketplace. At best, the vocal public can insist on the long-term view in the policy process, not short-term expediency.

In conclusion, government, because of its powers, is central to the issue of how long-term supply adequacy will be resolved. We do have a problem. We are on a collision course between growing demand and our ability to meet that demand. Positive government actions are indicated. Perhaps, most importantly, the Federal Government can rearticulate the goals of national energy policy.

In the meantime, the electric utility industry is focusing its planning on this critical time frame. We urge Congress to participate with us and our customers to insure that the worst does not come to pass while there is now time to prevent it.

The CHAIRMAN. Thank you very much, Mr. Smith.
Mr. Kaslow.

STATEMENT OF JOHN F. KASLOW, EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER, NEW ENGLAND ELECTRIC SYSTEM

Mr. KASLOW. Thank you very much, Mr. Chairman.

My name is John F. Kaslow and I am executive vice president and chief operating officer of the New England Electric System. It's a pleasure for me to appear before the committee today to discuss how we are working to assure an adequate supply of electricity at the lowest cost for the more than 1.2 million customers of New England Electric System companies.

If I may, Mr. Chairman, I would like to submit for the record a statement by Mr. William Ellis, who is chairman of the executive committee of the New England Power Pool. This will deal with New England wide issues.

The CHAIRMAN. That statement will appear in the record at the conclusion of the testimony by you, Mr. Kaslow.

Mr. KASLOW. Our company and New England as a whole was severely impacted in the 1970's because of a very heavy dependence on imported fuel oil. The region's dependence on oil also underscored the need to complete two new nuclear units well along in construction, and more recently to undertake a major two-phase project to import hydroenergy from Quebec.

Assuming completion of the nuclear units I referred to, Millstone 3 in Connecticut, and Seabrook 1 in New Hampshire, and the hydro-Quebec interconnection, we as a company do not anticipate the need for new capacity until at least the mid-1990's, though New England as a whole may need capacity a year or two earlier.

As we look to the year 2000, we are convinced that the best interest of our customers will be served by a process we term "balanced least cost planning, 'a process that applies consistent and unbiased economic criteria to options to decrease demand, as well as those options to increase supply.

We believe this process should permit reducing growth in the long-term demand in our own system below 2 percent, and our hope is that 1.2 percent will be achievable. However, there is no guarantee that our load management and conservation efforts will be embraced by our customers. The supply option may be a necessity earlier than we currently expect. Even if our balanced planning program is successful, there is no question that eventually additional supply will be required.

As we look ahead, real supply options are quite limited. In our region, beyond the somewhat limited potential of cogeneration, coal-fired generation and energy imports from outside the region are the most likely supply sources for the near to mid term. Our currently planned import of hydroenergy from Hydro Quebec appears to be a good business deal for both Hydro Quebec and New England.

The Canadian utility has considerable surplus hydro capacity and energy, with potential for still further development. The energy delivered will save New England customers millions of dollars, and the Canadians—another point I would like to switch to here—the Canadians also appear to have the ability to build nuclear units in less time for less money and with less intervention than we do.

It's ironic that on one side of the international border this is possible, but a few miles to the south the nuclear option has all but disappeared. This is certainly food for thought for all of us.

The New England-Hydro Quebec interconnection will supply about 10 percent of New England's kilowatthour needs in 1990. We're comfortable at that level, and perhaps a level somewhat higher, but I don't believe it would make sense for a number of reasons for us to view Canada as our supply source of the future.

It follows, then, that we and all electric utilities need viable supply options, whether they be for the short-, mid-, or long-term. We must also be able to plan in a workable regulatory framework and to avoid price and cost levels and fluctuations that are upsetting to our customers, and that may threaten the economic health of our companies.

I'm sure the committee will hear many suggestions today and comments on a number of points, but I would like to briefly comment on four points before I close.

First is construction work in progress: The anti-CWIP approach of the past is a major contributor to the rate shock of today. The historic anti-CWIP approach did not solve problems; it merely postponed them. The compounding of interest during construction for long lead time plants results in very expensive completed plants. As a result, regulators seek to temper the rate shock for completed facilities by phase-ins and disallowances which only serve to raise long term costs and cause utilities to avoid the financial risk of undertaking new plant construction.

Assuming that a supply source is necessary to meet future needs, and that it is recognized at the outset as the most economic alternative, it would appear that the best interests of the customer and sharehold alike would be served by some form of CWIP. Under the current Federal Energy Regulatory Commission rule, regulators and utilities continually evaluate construction programs from a least cost perspective. The FERC 50 percent solution to CWIP represents a careful balance that we feel should be maintained.

The second point I would like to comment on is regional regulation proposals: The effort to create a new layer of regulation is premised on the notion that the present system cannot handle the job. The premise we believe is false. Local, State, and Federal regulators generally do their jobs thoroughly. They make decisions along well defined lines of responsibility, and we don't believe a fourth layer is necessary.

Regional regulation will have neither the legal authority nor the political concensus to make the hard choices necessary for future energy supply. Both elements exist in the present regulatory scheme, and a fourth layer does not turn out to be one-stop shopping, but simply another-stop shopping.

I will cut short my comments on the text. If you have further questions on the regional regulations, I would be happy to address them. But I would like to move to environmental legislation.

Certainly our industry takes no issue with well-founded environmental legislation. What has been so difficult to deal with, however, is the tinkering with reasonable, fundamental environmental legislative policies which often leads to a complex maize, one where the mechanics of the process becomes more compelling than the basic environmental objective. There may ultimately be a path through the maize, but the attendant delays can be a principal contributor to the long lead times and subsequent high cost of major projects.

On a more specific point, legislative signals can affect the risk perception associated with generation options. Coal-fired generation is perhaps the only real baseload generation option today. Existing legislation, principally the Clean Air Act, poses substantial hurdles for siting and licensing a new coal fired unit.

However, the prospect of adding a new layer of regulation via acid rain legislation can substantially increase the dimension of the problem facing coal-fired plants. Hopefully, the completion of ongoing research on acid rain will define what, if any, fix is required. If a remedy is needed, it should be pursued within the context of the Clean Air Act, and not as a piece of add-on legislation.

I will try to abbreviate my comments on rail transportation costs. We, along with many others, think the Staggers Act needs to be revisited and some fundamental problems corrected. We are also concerned that the administration's ConRail proposal will help reduce competition, which we think is vital to controlling rail rates. Again, I would be happy to try to answer any questions on that subject.

Let me make just a few concluding remarks. We, at New England Electric, believe that our long term strategy of balanced least cost planning will meet our customers needs at lowest costs, but we must be sure that we maintain options. Over the past several years, the number of real options has shrunk. While we as utility managers accept the responsibility of meeting our customers needs, we must look to governments at all levels to develop, implement, and execute policies that truly preserve and enhance options to meet those needs adequately and at the lowest reasonable cost.

I thank you.

[The prepared statements of Mr. Kaslow and Mr. Ellis follow:]

Testimony of John F. Kaslow
New England Electric
Senate Energy Committee Hearing
July 23, 1985

My name is John F. Kaslow. I am Executive Vice President and Chief Operating Officer of the New England Electric System (NEES).

It is a pleasure to appear before this Committee today to discuss how we are working to assure an adequate supply of electricity at the lowest cost for the more than 1.2 million customers of the New England Electric System companies.

Let me describe briefly our company and its operations. Our wholesale generation and transmission company owns and operates oil and coal fired units - and several hydro units. It also has stock ownership in four operating nuclear plants and is a joint owner of two nuclear units in advanced stages of construction. Retail subsidiaries in Massachusetts, Rhode Island and New Hampshire provide electric service to over 1.2 million customers. Other System subsidiaries are involved in oil and gas exploration, providing energy conservation services - and in building a major D.C. interconnection between New England and the Province of Quebec.

The basic responsibility for meeting our customers' electric needs rests with the management of our companies. However, utilities must look to governments at all levels to establish and maintain policies that do not unnecessarily interfere with - and, hopefully, contribute to meeting our goal of adequate service at lowest cost.

In the next few minutes I will describe my Company's approach to meeting the future needs of our customers and some of our concerns.

Our company and New England as a whole were severely impacted in the 1970's because of heavy dependence on imported fuel oil. In 1973 NEES companies obtained 76% of their kilowatthours from oil. By virtue of a major coal conversion program we now produce 50% of our electric energy from coal - and only 25% from oil. The region's dependence on oil also underscored the need to complete two nuclear units well along in construction - and, more recently, to undertake a major, 2 phased project to import hydro energy from Quebec.

Price induced conservation, coupled with a slow paced regional economy kept our company's electric energy growth rate low in the period 1973 through 1982 - growth averaged about 1%/yr. However, a strong economic recovery in 1983/84 produced growth rates of roughly 5%. We see a tapering off in 1985 and believe that an inherent growth rate of less than 2%/yr. may be a more sustainable long term growth rate for our company.

At this rate - and assuming completion of the Millstone 3 and Seabrook I nuclear units and the Hydro Quebec interconnection , we do not anticipate the need for new capacity until at least the mid 1990's - though New England as a whole may need new capacity a year or two earlier.

As we look to the year 2000 we are convinced that the best interests of our customers will be served by a process we term

BALANCED PLANNING - a process that applies consistent and unbiased economic criteria to options to decrease demand as well as to options to increase supply. We believe that this process should permit reducing growth in the long term demand below 2% - and our hope is that 1.2% will be achievable.

However, there is no guarantee that our load management and conservation efforts will be embraced by our customers. The supply option may be a necessity earlier than we currently expect. Even if our balanced planning program is successful, there is no question that eventually additional supply will be required.

As we look ahead, real supply options are quite limited. In our region, beyond the somewhat limited potential of cogeneration and alternate energy sources that would be non-coal based, coal fired generation and energy imports from outside the region are the most likely supply sources for the near to mid term.

Our currently planned import of hydro energy from Hydro Quebec appears to be a good business deal for both Hydro Quebec and New England. The Canadian utility has considerable surplus hydro capacity and energy with potential for further development. The energy delivered will save New England customers millions of dollars. The Canadians also appear to have the ability to build nuclear units in less time, for less money and with less intervention than we do. It is ironic that on one side of the international border this is possible - but a few miles to the south the nuclear option has all but disappeared. This is certainly food for thought.

The New England/Hydro Quebec interconnection will supply about 10% of New England's KWH needs in 1990. We're comfortable at that level and perhaps at a level somewhat higher but I don't believe it would make sense for a number of reasons for us to view Canada as our supply source of the future.

It follows, then, that we - and all electric utilities - need viable supply options whether they be for the short, mid or long term. We must also be able to plan in a workable regulatory framework and to avoid price and cost levels and fluctuations that are upsetting to our customers - and that may threaten the economic health of our companies.

I'm sure the Committee will hear, in testimony today, the full gamut of industry concerns with respect to meeting future needs at lowest cost. However, I would like to comment on four issues which impact supply and cost and our ability to meet the dual goal of adequate supply at lowest cost:

(1) CWIP
(2) Regional Regulation
(3) Environmental Regulation
(4) Coal Transportation Costs

(1) CWIP

The anti-CWIP approach of the past is a major contributor to the rate shock of today. The historic anti-CWIP approach did not solve problems - it merely postponed them. The compounding of interest during construction for long lead time plants results in very expensive completed plants. As a result regulators seek to temper the rate shock for completed facilities by phase-in's and disallowances which only serve to raise long term costs - and cause utilities to avoid the financial risk of undertaking new plant construction.

Assuming that a supply source is necessary to meet future needs - and that it is recognized at the outset as the most economic alternative, it would appear that the best interests of the customer and shareholder would be served by some form of CWIP. Under the current Federal Energy Regulatory Commission (FERC) rule, regulators and utilities continually evaluate construction programs from a least cost perspective. The FERC 50% solution to CWIP represents a careful balance that should be maintained.

(2) REGIONAL REGULATION PROPOSALS

The effort to create a new layer of regulation is premised on the notion that the present system cannot handle the job. The premise is false. Local, state and federal regulators generally do their jobs thoroughly. They make decisions along well-defined lines of responsibility. A fourth layer is not necessary. Regional regulation will have neither the legal authority nor the political consensus to make the hard choices necessary for future energy supply. Both elements exist in the present regulatory scheme.

A fourth layer of regulation is not one-stop shopping. It is another stop shopping. Federal, state and local approvals for new plants should be and are now required. The three level review is sufficient to arrive at a correct result. A fourth layer adds only expense, uncertainty, and delay. All threaten our ability to respond quickly and effectively to our customers' needs. Regional regulation is not needed.

(3) ENVIRONMENTAL LEGISLATION

Certainly our industry takes no issue with well founded environmental legislation. What has been difficult to deal with, however, is the tinkering with reasonable, fundamental environmental legislative policies - which often leads to a complex maize - one where the mechanics of the process becomes more compelling than the basic environmental objective. There may ultimately be a path through the maize but the attendant delays can be a principal contributor to the long lead times and subsequent high cost of major projects.

On a more specific point, legislative signals can affect the risk perception associated with generation options. Coal fired generation is perhaps the only real base load generation option today. Existing legislation - principally the Clean Air Act - poses substantial hurdles for siting and licensing a new, coal fired unit. However, the prospect of adding a new layer of regulation via Acid Rain legislation - can substantially increase the dimension of the problem facing coal fired plants. Hopefully, the completion of on-going research on Acid Rain will define what, if any, fix is required. If a remedy is needed it should be pursued within the context of the Clean Air Act - and not as a piece of "add-on" legislation.

(4) RAIL TRANSPORT COSTS

The relationships among government policies are illustrated by the Staggers Act's solution to rail problems. In 1980, the railroads were in tough financial condition; the Staggers Act solution was deregulation. However, the result is that utility customers are being forced to support the financial integrity of railroads and cross subsidize other shippers.

Competition was the intended answer. We are trying to make it work for our company. Because of our fortunate position, we have been able to get contracts with three rail carriers. But the competition has not resulted in reasonable rail rates when compared to the railroads' costs of providing our rail services. Further, under the Administrations's Conrail proposal, two of the three rail carriers will merge. Competition would diminish. Coal costs could increase. The economics of coal burning could be impaired.

We should not rely on rail competition as a ground for deregulation and then allow mergers to eliminate the underlying justification. We should not expect utility customers to bear the primary burden for maintaining the financial integrity of rail carriers. Direct regulation and fair cost-based rail rates are the best answer. The Staggers Act should be amended and its fundamental problems should be corrected. We should also maintain the limited competition that now exists for the rail transportation of coal. The Conrail-N&W merger proposed by the Administration should be rejected.

CONCLUSION

We at New England Electric believe that our long term strategy of balanced planning - a process that will make the most effective use of options to decrease demand as well as options to increase supply - will meet our customers' needs at lowest cost. But we must be sure that we maintain options. Over the past several years the number of real options has shrunk. While we as utility managers accept the responsibility of meeting our customers needs, we must look to governments at all levels to develop, implement and execute policies that truly preserve and enhance options to meet those needs adequately - and at the lowest reasonable cost.

STATEMENT OF
WILLIAM B. ELLIS

CHAIRMAN, NEW ENGLAND POWER POOL EXECUTIVE COMMITTEE
AND
CHAIRMAN AND CHIEF EXECUTIVE OFFICER
NORTHEAST UTILITIES

FOR THE
SENATE ENERGY COMMITTEE
HEARING
"WHEN THE LIGHTS GO OUT"

WASHINGTON, DC
JULY 23, 1985

Mr. Chairman and members of the committee, I am unable to appear before you today in person, but would like to submit, for the record, the following statement which in my capacity as chairman of The New England Power Pool (NEPOOL) Executive Committee, describes the present status of generating capacity and reserve in New England and outlines some of the present and future challenges facing the utilities of this region.

NEPOOL is a voluntary association of the electric utilities in New England. Formed in 1971, NEPOOL is based in West Springfield, Massachusetts, and it represents 92 individual public and investor-owned utilities. NEPOOL's primary function is to plan, coordinate, monitor, and direct the operations of the region's major generation and transmission (bulk power supply) facilities. NEPOOL plans and coordinates for New England's electrical requirements as one integrated system. Member utility companies within the NEPOOL system account for more than 99.5 percent of the electric generation and transmission in the six New England states. The objective of NEPOOL is to assure both maximum economy and reliability of bulk power supply in New England for approximately 5 million customers served by member companies.

NEPOOL has an installed generating capacity of approximately 21,200 MW in the summer and 22,100 MW in the winter.

New records for peak demand were set on the NEPOOL system when the summer peak reached 16,274 MW on June 11, 1984 and the winter peak climbed to 16,940 MW on January 21, 1985.

For two consecutive years, 1983 and 1984, electrical consumption by customers of the NEPOOL member companies has risen

THREE TIMES FASTER THAN THE AVERAGE ANNUAL GROWTH RATE IN NEW ENGLAND IN THE YEARS SINCE 1972.

ALTHOUGH NEW ENGLAND AS A WHOLE SAW AN ENERGY GROWTH RATE OF 1.6 PERCENT FROM 1972 THROUGH 1982, ELECTRICAL USE INCREASED 4.9 PERCENT IN 1983 AND 4.7 PERCENT IN 1984. THROUGH MAY OF 1985 GROWTH HAS AVERAGED 2.8 PERCENT IN SPITE OF UNUSUALLY MILD WEATHER CONDITIONS PREVAILING THROUGHOUT THE REGION.

WHILE LOAD GROWTH HAS CLIMBED RAPIDLY, NO SIGNIFICANT NEW GENERATING CAPACITY HAS BEEN ADDED. THE LAST MAJOR BASELOAD FACILITY PLACED IN SERVICE WAS MILLSTONE 2, IN WATERFORD, CONNECTICUT, COMPLETED IN 1975. THE LAST NEW INTERMEDIATE-PEAKING PLANT WAS STONY BROOK AT LUDLOW, MASSACHUSETTS, IN 1981.

LOOKING AT NEPOOL'S CURRENT OPERATIONS, ONE QUICKLY CONCLUDES THAT THERE IS NO GENERATING SURPLUS IN NEW ENGLAND AT THE PRESENT TIME. SUPPLEMENTING THIS STATEMENT, THE "NEPOOL FORECAST OF NEW ENGLAND ELECTRIC ENERGY AND PEAK LOAD 1985-2000" (APPENDIX I) AND THE "NEPOOL FORECAST REPORT OF CAPACITY, ENERGY, LOADS AND TRANSMISSION, 1985-2000," (APPENDIX IA) WHICH PROVIDE THE TECHNICAL BASIS FOR PLANNING IN THIS TIME FRAME ARE APPENDED.

THE FOLLOWING IS A BRIEF DESCRIPTION OF THE CAPACITY SITUATION FACING NEPOOL UTILITIES FOR THE BALANCE OF 1985 AND INTO EARLY 1986.

NEPOOL IS LOOKING AT A 24 PERCENT RESERVE MARGIN FOR THIS SUMMER AND A 27 PERCENT RESERVE MARGIN FOR THIS COMING WINTER.

AT FIRST GLANCE, THESE RESERVES MAY SEEM COMFORTABLE, AS COMPARED TO OTHER REGIONS OF THE COUNTRY, BUT, CONSIDERING THE ACTUAL OPERATING CHARACTERISTICS OF NEW ENGLAND AS ONE ELECTRIC

SYSTEM, THEY ARE NOT. FOR ONE THING, NEW ENGLAND'S ACCESS TO OTHER POWER SYSTEMS IS LIMITED. THE REGION HAS OCEAN ON TWO SIDES--EAST AND SOUTH--AND SCANT TIES TO THE NORTH AND WEST. MANY OTHER REGIONS IN THE UNITED STATES CAN GET EMERGENCY HELP FROM NEIGHBORING SYSTEMS ON THREE OR FOUR SIDES; NEW ENGLAND CAN'T AND, THEREFORE, HAS TO BE SOMEWHAT MORE SELF-SUFFICIENT.

PART OF RESERVE MARGIN IS SUPPOSED TO PROVIDE TIME FOR PLANNED MAINTENANCE. ORDINARILY, PLANNED MAINTENANCE SHOULD BE KEPT TO A MINIMUM DURING THE PEAK MONTHS. PROVIDING FOR A PEAK IN THE WINTER AND A SIMILARLY LARGE PEAK IN THE SUMMER--AS OCCURS IN NEW ENGLAND--DOES NOT LEAVE SUFFICIENT TIME IN SPRING AND FALL FOR ALL REQUIRED MAINTENANCE DURING THE VALLEY PERIODS, SO SOME OF THAT MAINTENANCE HAS TO BE DONE DURING THE POTENTIAL PEAK PERIODS. ONCE AGAIN, NEW ENGLAND'S OPERATING CHARACTERISTICS REQUIRE AN EXTRA MEASURE OF CAPACITY.

AND, SOME OF THAT RESERVE IS NEEDED TO COVER THE EVER-PRESENT PROBLEM OF UNANTICIPATED PLANT SHUTDOWNS. IN FACT, MORE THAN HALF OF THAT 24 PERCENT SUMMER RESERVE CAN BE ATTRIBUTED TO SUCH UNPLANNED OUTAGES. NEPOOL COMPANIES ARE UNDERTAKING PROGRAMS TO REDUCE THIS OUTAGE EXPERIENCE, WHICH MAY BE THE RESULT OF ANY NUMBER OF FACTORS, INCLUDING THE AGE OF PLANTS AND THE INDIRECT EFFECTS OF CONSTRAINED PLANNED MAINTENANCE PERIODS.

WITH THOSE CIRCUMSTANCES AT WORK, NEW ENGLAND HAS A VERY TIGHT CAPACITY SITUATION FOR THE REST OF THIS YEAR. IN FACT, EVEN WITH NORMAL WEATHER AND NORMAL LOADS, IT WAS ORIGINALLY FORECAST THAT NEPOOL WOULD EXPERIENCE CAPACITY DEFICIENCIES DURING 400 TO 500 HOURS FROM MAY THROUGH DECEMBER 1985.

In this situation, NEPOOL is required to implement an Emergency Operating Procedure No. 4, (Action During a Capacity Deficiency) which allows NEPOOL to call for the maximum generating capability in New England, to purchase emergency power from Neighboring power pools, and to use a variety of other emergency measures in obtaining the necessary load relief. As previously stated, due to unusually moderate weather conditions so far this year, NEPOOL has been forced to implement OP 4 on only three occasions to date.

However, if there is extremely hot weather or a prolonged heat wave before summers end, it's expected that NEPOOL and all member companies will even have to use some "last resort" measures under OP 4--namely, a 5 percent voltage reduction and a public appeal for voluntary load curtailment.

It is important to note, however, that a voltage reduction is a technical means of obtaining load relief and is virtually indiscernible to customers.

Emergency Operating Procedure (OP 4) was implemented 13 different times in 1984, but the pool-wide voltage reduction measure was not required last year. Because of sustained load growth, extended scheduled outages, and the prospect of less assistance than anticipated from neighboring pools, it is probable that this procedure (OP 4) will be implemented on a number of occasions in 1985 in order to provide uninterrupted electrical service to New England customers.

However, despite the capacity deficiency problems anticipated through 1985, it appears that NEPOOL's capacity situation will

BEGIN TO IMPROVE IN 1986 BECAUSE OF THE PLANNED ADDITION OF MAJOR NEW RESOURCES.

FIRST, THE 150-MW VERMONT HIGHGATE INTERCONNECTION WITH HYDRO-QUEBEC, INITIATED BY THE STATE OF VERMONT, IS SCHEDULED FOR COMPLETION IN THE FALL OF 1985.

THEN, THE 1,150-MW MILLSTONE 3 GENERATING STATION IN CONNECTICUT IS PLANNED FOR COMMERCIAL OPERATION IN MAY 1986.

THE NEPOOL/HYDRO-QUEBEC PHASE I INTERCONNECTION IS AHEAD OF THE ORIGINAL SCHEDULE AND IS NOW EXPECTED TO BE COMPLETED BY JULY 1, 1986. THIS WILL RESULT IN THE DELIVERY OF FOUR BILLION KILOWATT-HOURS OR MORE OF SURPLUS ENERGY ANNUALLY TO NEW ENGLAND, AND SHOULD BE AVAILABLE FOR EMERGENCY PURCHASES TO HELP REDUCE THE NUMBER OF TIMES EMERGENCY PROCEDURES WOULD NEED TO BE IMPLEMENTED.

NEW HAMPSHIRE YANKEE PRESENTLY PROJECTS A LATE 1986 COMPLETION DATE FOR SEABROOK 1 WHICH WILL ADD ANOTHER 1,150-MW TO NEW ENGLAND'S GENERATING CAPABILITY. CONSTRUCTION MANAGEMENT HAS THIS PROJECT WELL IN HAND, AND THE ENERGY REQUIREMENTS OF THE REGION DEMAND THAT IT BE FINISHED AS SOON AS POSSIBLE.

BY 1990, THE PHASE II NEPOOL/HYDRO-QUEBEC FACILITIES SHOULD BE COMPLETED, ENABLING NEPOOL COMPANIES TO ADD AN ADDITIONAL SEVEN BILLION KILOWATT-HOURS ANNUALLY TO THE REGION'S ENERGY SUPPLY MIX. CONTRACT AGREEMENTS ARE NOW BEING FINALIZED AND IT IS ANTICIPATED THAT ALL DOCUMENTS WILL BE READY FOR EXECUTION BY THE FALL OF THIS YEAR.

IN ADDITION TO THESE RESOURCES, OTHER FACTORS IMPROVE THE NEPOOL CAPACITY OUTLOOK FOR THE NEXT FIVE YEARS.

NEPOOL forecasts a more moderate load growth of 2.1 percent and some NEPOOL companies hope to achieve an even slower growth rate in the years ahead.

Conservation, utility and customer load management, cogeneration, and renewable energy sources have become a significant and growing portion of the new resources planned by NEPOOL companies. Based on the most recent projections by New England utilities, NEPOOL now expects that cogeneration and qualifying small power production facilities will supply more than 8 percent of the region's electrical requirements in 1990.

Three unique new capacity additions are included in this category of generation sources as recently announced by the Boston Edison Company, one of the largest of the NEPOOL members. The first is a 10 MW peat-burning facility to be constructed in Maine for late 1986 operation. The second is a large wind farm in western Massachusetts which will comprise of 115 wind turbines with a total capacity of 10 MW. The third is a 80 MW cogeneration facility which will be built in Everett, Massachusetts adjacent to Edison's Mystic Station. This cogenerator will burn anthracite wastes and other fuels and is scheduled for 1989 operation.

As an example of the type of planning being done by individual utilities, also appended is an abstract of Northeast Utilities Integrated Demand/Supply Planning (Appendix II) process presented to the Connecticut Department of Public Utility Control in June, 1985.[1] This document will provide the blueprint for planning for New England's largest utility for the balance of this century.

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[1] FOR A DESCRIPTION OF NORTHEAST UTILITIES SERVICE AREA, CUSTOMER BASE AND GENERATION MIX, SEE APPENDIX III.

However, with the surge of economic growth in New England over the past two years, even the most strenuous efforts to control load growth seem to be overwhelmed. Special additional efforts are called for, and many are under way.

For example, NEPOOL companies are committed to make maximum use of existing facilities, and there'll be an increased investment in existing generating units to increase availability and to lower unplanned outage rates.

NEPOOL companies will also invest to extend the life of generating facilities and to convert certain units to dual and triple fuel capability where conversion is economically justified.

And, by 1990, New England utilities will have invested more than three quarters of a billion dollars in facilities to import significant amounts of electric energy from Canada.

In the next five years, NEPOOL companies will become more and more reliant on load growth containment through conservation and load management programs, on maximizing the use of existing facilities, on purchasing capacity and energy from small power producers and cogeneration facilities, and on purchases from Canadian sources. While utility plans and proposals have to be smart, creative, and daring, lots of guidance and cooperation from federal, state and local regulators and other public officials will be required to make these utility programs possible. The outlook for the economy of New England and for the region's ability to maintain and create jobs is at stake.

However, even combined with the added energy and capacity of Millstone 3, Seabrook 1 and Hydro-Quebec, these measures are not

LIKELY TO ELIMINATE THE NEED FOR SOME MAJOR NEW RESOURCES IN THE 1990'S ESPECIALLY IF LOAD GROWTH CONTINUES TO EXCEED 2 PERCENT ANNUALLY.

EVEN WITH SUPERHUMAN ACCOMPLISHMENTS IN COGENERATION SOURCES, CONSERVATION AND LOAD MANAGEMENT, DEFICIENCIES IN THE 1990'S COULD BE GREAT ENOUGH SO THAT NEW ENGLAND MAY NEED, SOONER OR LATER, NEW BASELOAD GENERATING CAPACITY, EVEN IF THAT MEANS A NUMBER OF MEDIUM-SIZED FOSSIL STATIONS.

NEPOOL HAS LOOKED AT SEVERAL ALTERNATIVES FOR MEETING GENERATING NEEDS TEN YEARS FROM NOW AND ONE ELEMENT IS PERSISTENT. DIFFICULT PLANNING ACTIONS MUST HAPPEN IN THE NEXT YEAR OR TWO TO ENSURE THAT ENOUGH ELECTRICITY WILL BE AVAILABLE TO MEET CUSTOMER DEMAND IN THE NEXT DECADE.

ONE OPTION BEING CONSIDERED IS A FIRM CAPACITY PURCHASE FROM HYDRO-QUEBEC.

THE ADVANTAGE OF THIS PURCHASE MIGHT BE THAT NO NEW ENGLAND UTILITY CAPITAL WOULD BE REQUIRED TO BUILD THE FACILITIES IN QUEBEC. A DISADVANTAGE MIGHT BE THE RELATIVELY SHORT LIFE OF SUCH AN ENERGY SOURCE--20 YEARS--AS OPPOSED TO THE 30- TO 50-YEAR LIFETIME OF A GENERATING UNIT CONSTRUCTED IN NEW ENGLAND.

SUCH A PURCHASE FROM CANADA WOULD ALSO REQUIRE EXTENSIVE NEW TRANSMISSION CAPACITY BECAUSE THE PRESENTLY PLANNED HYDRO-QUEBEC INTERCONNECTION WILL BE LOADED TO ITS TRANSFER CAPABILITY WITH ENERGY DELIVERIES UNTIL THE YEAR 2000.

ADDITIONAL GAS TURBINE UNITS HAVE ALSO BEEN CONSIDERED FOR NEW ENGLAND, BUT EVEN THOUGH THIS GENERATING TECHNOLOGY HAS A RELATIVELY SHORT LEAD TIME AND LOW-CAPITAL COST, FUEL COSTS ARE VERY HIGH.

NEPOOL HAS CONSIDERED ONE OR MORE MEDIUM-SIZED COAL-FIRED GENERATING STATIONS AS ANOTHER ALTERNATIVE. ONE PROBLEM IS THAT HISTORY HAS PROVEN THAT BASELOAD COAL PLANTS WOULD REQUIRE AT LEAST TEN YEARS LEAD TIME FROM CONCEPTION TO COMPLETION.

COAL-FIRED GENERATION HAS A LOW-FUEL COST, BUT, IN NEW ENGLAND ESPECIALLY, LONG TRANSPORT REQUIREMENT AND NUMEROUS ENVIRONMENTAL CONCERNS WOULD PROBABLY INCREASE THE PRICE OF SUCH ENERGY SIGNIFICANTLY ABOVE PRESENT DAY LEVELS.

ANOTHER ALTERNATIVE BEING CONSIDERED BY NEPOOL AND SOME NEW ENGLAND UTILITIES IS A SECOND NUCLEAR FACILITY AT POINT LEPREAU IN NEW BRUNSWICK, CANADA.

AGAIN, NO CAPITAL WOULD BE REQUIRED UP FRONT FOR A SECOND POINT LEPREAU UNIT, BUT NEW TRANSMISSION CAPACITY WOULD BE NECESSARY FROM NEW BRUNSWICK ALL THE WAY TO MASSACHUSETTS.

THAT NUCLEAR PROJECT COULD HAVE AN EARLY ON-LINE DATE OF 1992, BUT A DECISION DEADLINE OF EARLY FALL 1985 HAS BEEN SET BY THE NEW BRUNSWICK ELECTRIC POWER COMMISSION FOR ANY NEW ENGLAND UTILITY WISHING TO PARTICIPATE.

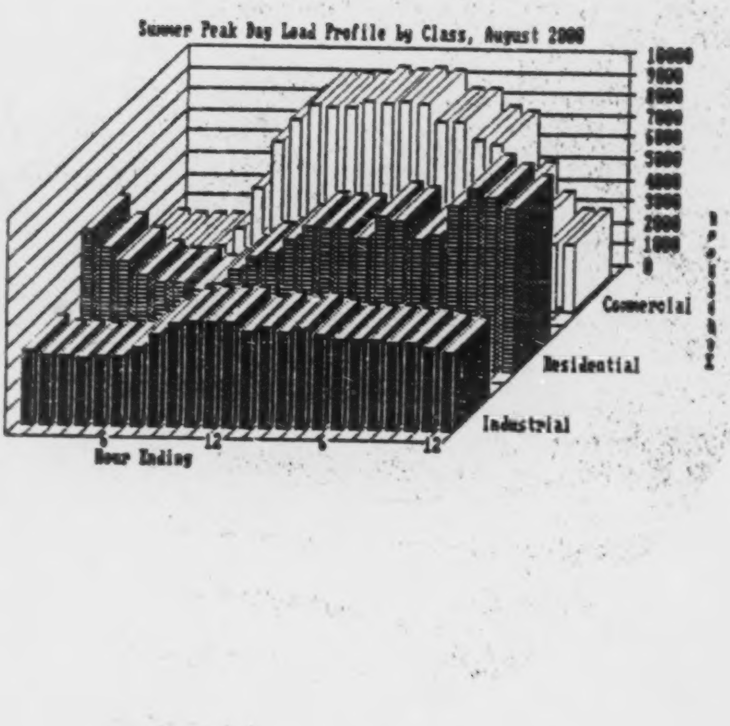
NEPOOL AND ITS MEMBERS WILL CONTINUE TO EVALUATE ALL ALTERNATIVES FOR THE CONTINUED DEVELOPMENT OF A LONG-TERM ECONOMIC AND RELIABLE ELECTRIC POWER SUPPLY SYSTEM. ALTHOUGH THERE APPEARS TO BE A STEADILY CLARIFYING NEED FOR GENERATION EXPANSION IN NEW ENGLAND, A CENTRAL GENERATING STATION OR OTHER NEW RESOURCE WILL REQUIRE A HEAVY BURDEN OF PROOF THAT BOTH UTILITIES AND PUBLIC OFFICIALS HAVE SQUEEZED ALL THAT'S AVAILABLE FROM CONSERVATION, COGENERATION AND ALTERNATIVE ENERGY SOURCES.

IN CONCLUDING THIS BRIEF SUMMARY OF NEW ENGLAND'S GENERATION STATUS AND FUTURE CAPACITY REQUIREMENTS, LET ME ADD THAT I WOULD BE GLAD TO RESPOND TO ANY SPECIFIC QUESTIONS THAT YOU, MR. CHAIRMAN, OR OTHER MEMBERS OF THE COMMITTEE MAY HAVE.

(Committee Note: Appendix I and Appendix III follow. Appendix IA and Appendix II have been placed in Committee files.)

APPENDIX I

NEPOOL FORECAST OF
NEW ENGLAND
ELECTRIC ENERGY AND PEAK LOAD
1985-2000



Load Forecasting Task Force
April, 1985

NEPOOL FORECAST OF NEW ENGLAND ELECTRIC ENERGY AND PEAK LOAD

1985 - 2000

by the

Load Forecasting Task Force
State Forecast Analysts
NEPOOL Staff

Donald V. Bourcier, Chairman - New England Power Planning
Bruce G. Blakey - Northeast Utilities Service Company
Avery J. Caldwell - Bangor Hydro-Electric Company
Robert M. Coughlin - New England Power Planning
John P. Davulis - New England Power Planning
Peter C. DeGenring - Boston Edison Company
Dennis C. Delay - Public Service Co. of New Hampshire
William R. Ferner - The United Illuminating Company
Robert L. Fratto - Commonwealth Electric Company
Edward J. Glofka - New England Power Exchange
Derek H. Howell - Northeast Utilities Service Company
James A. Lahtinen - Central Vermont Public Service Co.
Shannon M. Larson - Boston Edison Company
Frank T. Lin - New England Power Service Company
John F. Marien - EUA Service Corporation
Lydia M. Pastuszek - New England Power Service Company
Darrel R. Quimby - Central Maine Power Company
Richard F. Spellman - Central Maine Power Company
Robert L. Stinson - Mass. Municipal Wholesale Electric Co.
Bruce E. Urbschat - New England Power Planning
Peter T. Zschokke - Central Vermont Public Service Company

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I. EXECUTIVE SUMMARY

This report presents the NEPOOL 1985-2000 forecast of electric energy and peak load demand for New England. The projection has been prepared by the Load Forecasting Task Force, State Forecast Analysts and NEPOOL staff. The NEPOOL Model for Long-Range Forecasting of Electric Energy and Demand serves as the basic tool for developing the forecast.

Since the forecast is used in a NEPOOL planning context, the primary focus is to produce most likely estimates of future levels of electric energy and peak load for New England as an entity even though the forecast is developed using state-specific data. Accordingly, this report presents the forecast and major assumptions on a regional basis.

Exhibit I-1 summarizes the current forecast for peak loads, energy sales by class of service, net energy for load and annual load factor. Also shown are projections for the major economic and demographic factors underlying growth in New England electricity use. It is the expectation of the Load Forecasting Task Force that New England will soon become a summer peaking system.

Summer peak load is projected to increase to a level of 22,670 MW in the year 2000--an annual growth rate of 2.1 percent from the 1984 weather-corrected summer peak load of 16,300 MW. Growth in winter peak load is expected to be 1.7 percent per year for the 1984-2000 period. A load of 22,260 MW is forecasted for the winter of 2000/01. Net energy for load is projected to increase at an annual rate of 2.1 percent. The annual load factor is expected to increase from 62.5 percent in 1984 to 65.1 percent in 2000.

Exhibit I-2 shows the historic and projected relationship between summer and winter peak load. New England's summer peak load has grown from about 85 percent of the subsequent winter peak in the mid-1960s to near parity in the early 1980s. It is forecasted that the summer peak will exceed the winter load by 1988.

The cumulative growth in summer peak load for the projection period is compared with that experienced during the 1970-1984 interval in Exhibit I-3. Also shown in the exhibit is the magnitude of load management that New England companies expect to achieve during the forecast horizon. In the aggregate, approximately 1,015 MW of load management are included in the forecast for the summer of 2000 and 1,050 MW for the winter of 2000/01.

A characteristic of any forecast is uncertainty. Projections of energy consumption are subject to a high degree of uncertainty due to changes in the supply side of the world market structure for various energy sources and to fluctuations of growth in the U.S. and regional economy. The current long-term forecast represents best estimates of model formulations and forecast assumptions for the region.

EXHIBIT I-1

NEW ENGLAND FORECAST SUMMARY, 1984 - 2000

		Projected				Compound Annual Growth Rate 1984-2000 (%)
	1984*	1985	1990	1995	2000	
Coincident Peak Load (MW)						
Winter (beginning)	16,900 (wc)	17,520	18,520	20,570	22,260	1.7
Summer	16,300 (wc)	17,190	18,790	20,920	22,670	2.1
Energy Sales to Ultimate Customers (GWh)						
Total	84,900	88,120	96,440	108,790	119,240	2.1
Residential	31,200	31,930	33,940	38,460	42,560	2.0
Industrial	22,800	23,910	26,810	30,260	33,920	2.5
Commercial and Other	30,900	32,280	35,690	40,070	42,760	2.1
Net Energy for Load (GWh)	92,500 (p)	95,350	104,640	118,020	129,330	2.1
Annual Load Factor (%)	62.5 (p)	62.1	63.6	64.4	65.1	--
Economic/Demographic						
Population (000s)	12,578	12,683	13,246	13,753	14,140	0.7
Households (000s)	4,613	4,697	5,123	5,513	5,992	1.6
Employment (000s)	6,215	6,388	6,862	7,170	7,458	1.1
Manufacturing (000s)	1,466	1,525	1,637	1,652	1,687	0.9
Nonmanufacturing (000s)	4,240	4,368	4,834	5,174	5,406	1.5
Unemployment Rate (%)	5.2	4.9	4.1	4.3	5.0	--
Personal Income (bil.$79)	122	127	147	166	182	2.5

* - Estimated except where noted
wc - Weather corrected actual
p - Preliminary

NEPLAN
April 1, 1985

EXHIBIT I-2

Summer/Winter Peak Load Ratios

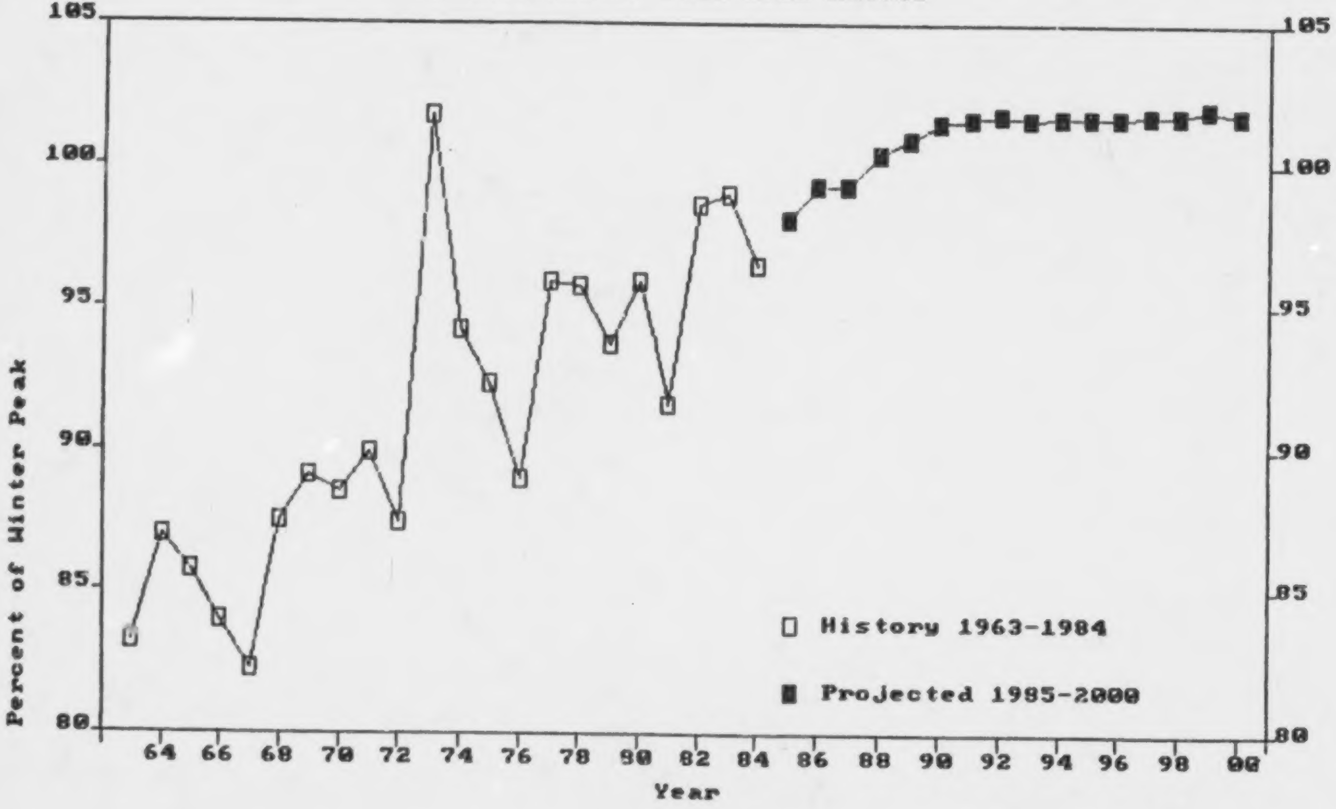
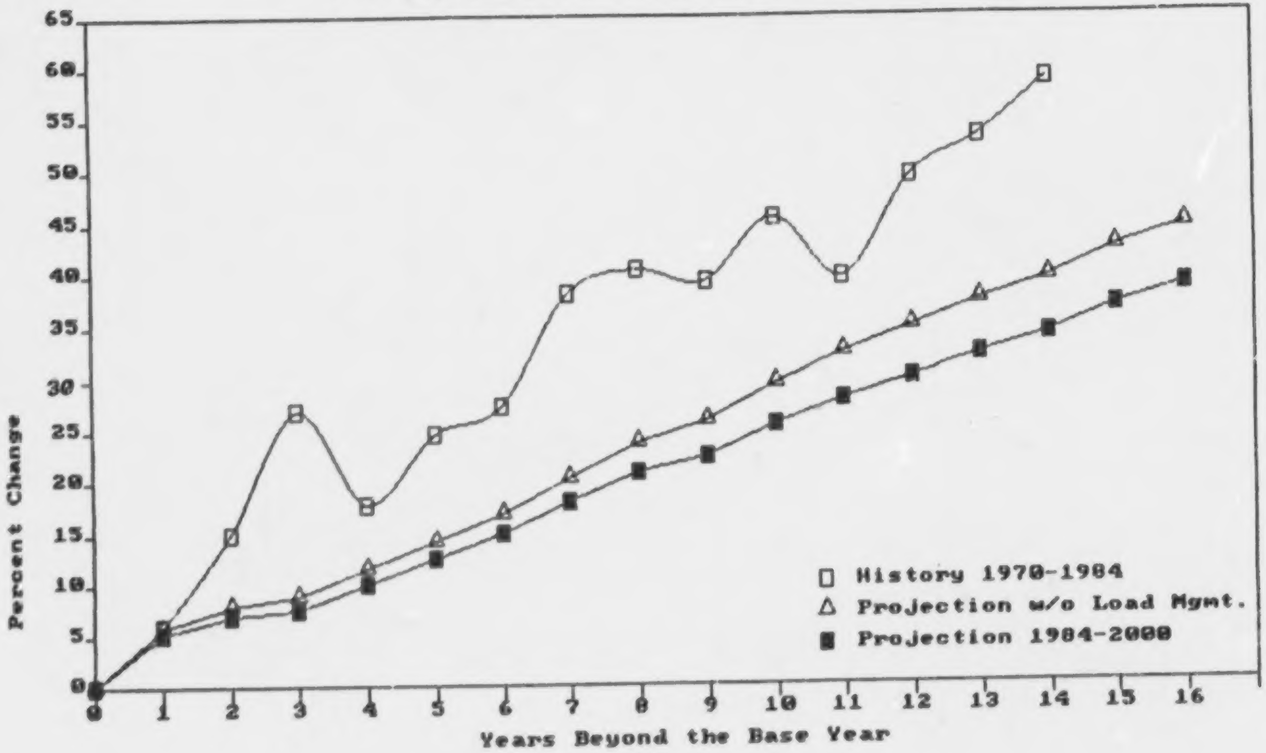


EXHIBIT I-3

Cumulative Growth in Summer Peak Load



II. MAJOR FORECAST ASSUMPTIONS AND METHODOLOGY

This projection was developed using the NEPOOL Model for Long-Range Forecasting of New England Electric Energy and Peak Demand (ref. 1). The forecast described is a conditional one; that is, the NEPOOL Model has been used to project the long-run behavior of consumers of electricity based upon a number of assumptions about other variables, such as economic/demographic growth and the price of electricity. The following brief description of the model's framework and key exogenous inputs is presented to enhance the reader's understanding of the current forecast. A more detailed description of the NEPOOL Model is available from NEPLAN upon request.

A. Economic/Demographic

This year's forecast directly employs regional economic and demographic projections developed for NEPOOL by Data Resources, Inc. using their Regional Information Service (RIS) Model (ref. 2). The RIS Model is export-based and econometric in nature. It generates a complete solution following a two-step process. First, the model is solved to determine the level of economic activity in each of nine RIS regions (of which New England is one). Then, the model is solved again to establish forecasts for the states within each region. The regional projections are both driven by and consistent with DRI's long-term forecast for the U.S. economy as a whole.

The DRI projections provide the NEPOOL Model with the fundamental growth factors necessary to estimate future electric energy use. Specifically, population, households, personal income, employment, and industrial production indices are used in the NEPOOL Model to generate a forecast.

In addition, a number of other exogenous inputs are used. These include price of electricity and fuel oil; price elasticities; government regulations; load management practices; and electric system line losses. Following is a brief discussion of these major input factors.

B. Energy Prices

The effects of changes in the price of electricity and fuel oil are explicitly represented in the forecast. This representation is in two forms. The model represents the impact of price changes on the rate of utilization of electricity by end-uses (e.g., individual appliances). The model also reflects the impact of prices on the determination of the electric share of those energy markets where competition exists (e.g., space heating equipment). The following discussion presents the assumptions used to determine these price effects.

Utilization of Electricity. The impacts of changes in real (constant dollar) electricity prices are determined for each of approximately 85 end-uses of electricity. This is accomplished by applying end-use specific short and long-run own-price elasticity coefficients to actual and projected real electricity prices. The important characteristic of the methodology used is that the impacts of electricity price changes not only are reflected in the short run (first year of price change) but also in the long run (over the expected useful life of the energy-using device). This is true during periods of increasing or decreasing real prices.

The end-use price elasticity coefficients reflect the sensitivity of consumers (i.e., households, industry, commerce) to price changes with respect to their utilization of electricity-using devices. Electricity is a derived demand. That is, electricity is only used to provide an actual service or function desired by the consumer. Thus, the sensitivity to electric price is manifested in the short run by altering the intensity of use of the electricity-using device and, more importantly, in the long run by changing the stock of energy-using appliances, processes or use patterns. Examples of changes occurring in the long term include the addition of insulation to physical structures, replacement of worn-out appliances, machines, lighting fixtures, etc. with more energy-efficient units, installation of supplementary nonconventional heating systems (wood, solar) which replace part of heating requirements, and a variety of capital additions which control or monitor the degree of energy use.

Therefore, given different elasticities by end-use and different mixes of end-use devices, it would be expected that class elasticities (residential, commercial, etc.) would differ over time and geographic areas. For 1983, the New England combined (weighted by end-use) long-run elasticities are as follows: total -0.74, residential -0.73, industrial -0.62, and commercial -0.84.

Electricity prices used in the determination of price impacts on electricity use include actual data for 1960-1983 and projections for 1984-1999. For each state, prices are specified by class of service and for heating and cooling use categories. The price projections are NEPOOL estimates which reflect DRI's projections for oil and coal prices and the general inflation rate (ref. 3,4), and NEPOOL's expected future electric supply capacity.

Exhibit II-1 compares the projected outlook for real electricity prices (adjusted for inflation using the Consumer Price Index) with historical experience (1984 is an estimate). There are distinct periods of price change. As a result of the oil embargo in 1974, the real price of electricity jumped 27 percent in one year. After four years (1975-1979) of stable or declining real prices, sharp increases were experienced again due primarily to the major increase in OPEC oil prices during 1980. The recessions which followed softened the oil market reducing the price of electricity.

The expected future path (1984-2000) of real electricity prices reflects modest fuel cost escalation and significant changes in New England's electric generation mix beginning in 1986. As new generating units are put into service, the real price is expected to rise reaching a peak in 1987. Real prices are expected to decline by 1.4 percent per year through 1987-1992. This price decline can be attributed to several factors. New nuclear units displace generating units with higher variable operating expenses. Further, interest costs and taxes decline steadily because no new plants are built. Oil and coal prices are

EXHIBIT II-1

Cumulative Growth in the Real Price of Electricity

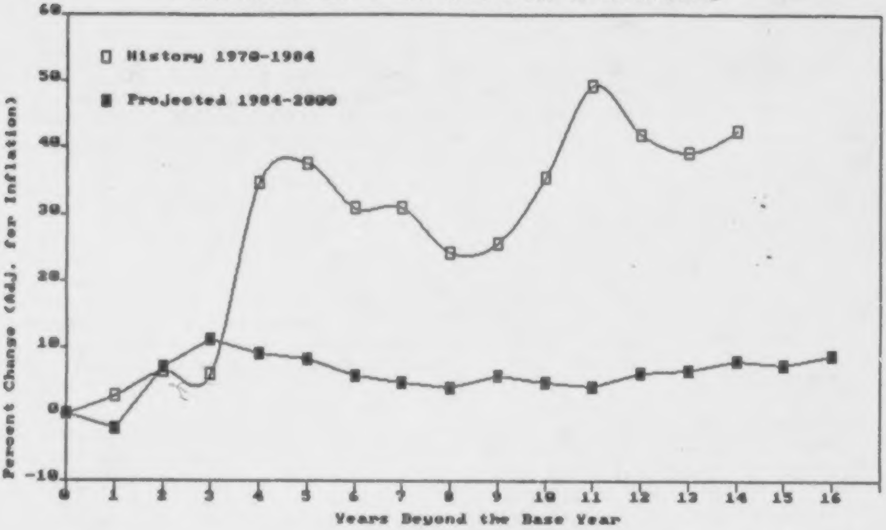
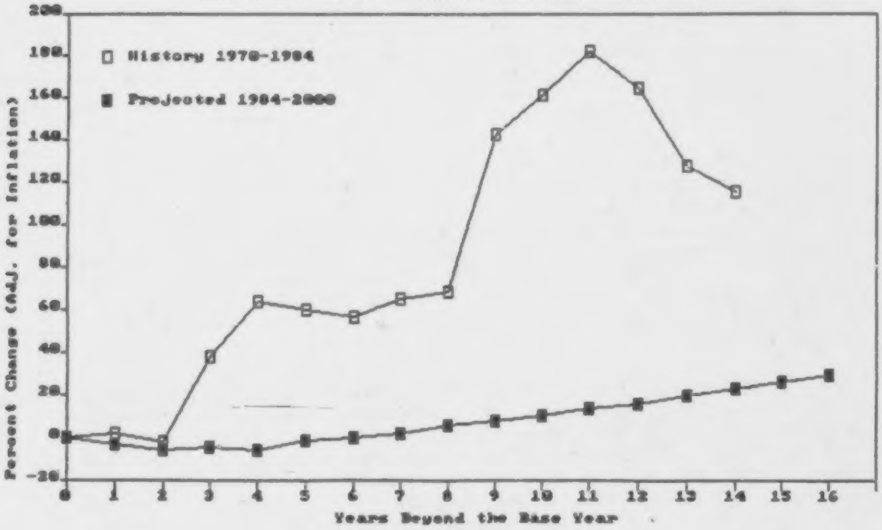


EXHIBIT II-2

Cumulative Growth in the Real Price of Fuel Oil



assumed to grow modestly, just above the rate of inflation. Thus, fossil-fueled generation costs are relatively low. Coal prices remain lower than oil and 1,427 MW of oil-fired capacity is converted to 1,256 MW of coal-fired capacity. Customer generation and life extensions of existing units defer the need for new generating capacity somewhat. What is probably most important, however, are purchases of electricity from Canadian sources. The Hydro-Quebec purchase begins at 3,000 GWh per year in 1987, increasing to 10,000 GWh by 1991, and declining to 7,000 GWh in 1998. The energy cost for this purchase is assumed to be less than fossil fuel costs. The purchase also allows the building of new capacity to be deferred.

The real price of electricity begins to rise in 1993 with slowly but steadily rising fuel costs and the installation of uncommitted coal and gas turbine generating capacity. At the end of the forecast period, the real price of electricity (1984 constant dollars) is projected to be 9.0 cents per kWh which is less than 10 percent above the estimated 1984 price of 8.3 cents per kWh.

The expected path for residential fuel oil prices 1984-2000, likewise, is different from historic experience (see Exhibit II-2). The basis for the projected price series is Data Resources, Inc. (ref. 4). Their projection calls for the real price of fuel oil to remain essentially flat through 1990. Thereafter, the price is forecasted to increase at an annual rate of 2.6 percent over inflation. In 2000, the real price of heating oil (1984 constant dollars) for the Boston market is expected to be $1.43 per gallon which is 29 percent above the estimated 1984 price of $1.10 per gallon.

In the residential sector of the NEPOOL Model, the marginal price of electricity for heating and the price of heating oil (adjusted for thermal efficiency) are the prime determinants of the forecasted electric space heating annual penetration rate. The electric share of the space heating market, in turn, is the major factor determining electric shares in the water heating and cooking markets. Thus, relative movements in the price of electricity and fuel oil are important. While New Englanders chose electric heat for about 44 percent of the new housing units constructed during the 1970-84 interval, examination of Exhibit II-1 and II-2 suggest that this will not happen during the forecast period (see also Exhibit IV-6).

C. Government Regulations

The forecast includes the impacts of several governmental regulations. These include decontrol of domestic crude oil and natural gas prices, appliance efficiency standards, and temperature restrictions in nonresidential buildings. Following is a brief description of these regulations and their representation in the forecast.

Appliance efficiency improvements are modeled after the U.S. Department of Energy's (DOE) proposed rules reflecting the Energy Policy and Conservation Act as amended by the National Energy Conservation and Policy Act of 1979 (ref. 5, 6, 7). Although the proposed rules have not been adopted, they are included in the forecast to capture the efficiency improvements which manufacturers are voluntary incorporating.

The efficiency improvements are adjusted to reflect the impact of consumer response to changing appliance efficiency (ref. 8). In effect, this adjustment is based on the assumption that consumers will use certain appliances more if efficiency improvements reduce the cost of using them. The greatest changes in adjusted efficiencies are expected for freezers, televisions and refrigerators.

Temperature Restriction Controls. Mandatory controls on temperatures for commercial buildings were initially imposed on July 16, 1979. President Reagan eliminated the mandatory temperature restrictions on February 17, 1981. The mandatory controls restricted temperatures to 78°F in the summer and 65°F in the winter. In the forecast, it is assumed that only government office buildings will maintain some aspects of the original program; i.e., a 3 percent reduction in air conditioning use and 1 percent in heating.

Miscellaneous Standards. Other energy efficiency standards such as ASHRAE 90-75R are not explicitly included in the forecast since it is expected that price-induced voluntary reductions in electricity consumption by consumers will in the long run yield at least the same end result as their explicit representation. Given the unprecedented increases in real electricity price that occurred during 1973-1981, this assumption is considered to be a reasonable one.

D. Load Management

The forecast explicitly represents load management targets set by the New England utilities and the estimated costs of implementing them. Specifically, residential storage electric space heating and water heating devices are represented as well as controlled commercial office cooling. Energy use of these devices is modeled in the following ways:

- Controlled storage water heating - No energy use during weekday hours ending 8 a.m. through 8 p.m. (13 hours). Since the unit is completely off during this extended period, a larger tank size than conventional is required with greater stand-by heat losses.
- Controlled storage space heating - No energy use during weekday hours ending 8 a.m. through 9 p.m. (14 hours).
- Controlled office cooling - Portion of cooling load shifted from weekday hours ending 11 a.m. - 5 p.m. over to hours ending 6 p.m. - 12 p.m. As temperature increases, a greater proportion of load is shifted. Energy losses accrue as temperature increases.

The following table shows the market shares expected for each device during the forecast period for New England as a whole:

	1990	2000
Controlled storage water heaters (share of total electric water heaters)	34%	64%
Controlled storage space heaters (share of total electric space heaters)	15%	21%
Controlled office cooling (share of total office cooling market)	36%	62%

The resultant saturations for storage water heating and storage space heating in 2000 are expected to be 21 percent and 4 percent of total households, respectively. Further, by 2000, 42 percent of all commercial office workers are expected to work in a load-controlled cooling environment. In addition to these load management devices, it is expected that interruptible load over the summer peak will increase by 254 MW during the forecast period. These levels of load management correspond closely with the current programs of NEPOOL participants.

E. New Technology

The impact of future technological change is implicitly included in the forecast to the extent that DRI's growth projections include such change. It is also assumed that the long-run price elasticity effects on conventional heating and cooling systems will capture the introduction of new methods such as solar heating and cooling.

Electric heat pumps (for both heating and cooling) are explicitly recognized. The saturation of heat pumps for heating is forecast to be 4 percent in 2000 while heat pumps for cooling are expected to attain a saturation of nearly 1 percent in the same year. Electric vehicles are not recognized in this year's forecast.

F. System Line Losses

Losses on the transmission and distribution system are based upon NEPOOL transmission load flow studies and distribution loss information from NEPOOL company data. Total line losses are expected to account for approximately 7.8 percent of net energy for load during the forecast period.

III. NEW ENGLAND ECONOMIC/DEMOGRAPHIC OUTLOOK

This chapter provides an overview of the regional economic projection developed for NEPOOL by Data Resources, Inc. in the Fall of 1984. The long-term outlook for New England is quite good (see Exhibits III-1 to III-4). For example, growth in population, manufacturing employment and real personal income is expected to exceed that experienced during the 1970-1984 period. Driven by a strong "high technology" sector, the unemployment rate for the region is projected to remain below 5 percent for most of the forecast period.

A. Population

The population of New England is projected to increase to 14.1 million in the year 2000 for an annual increase of 0.7 percent. This compares with an actual growth rate of 0.4 between 1970 and 1984 (see Exhibit III-1). The improvement in the region's population growth rate reflects an expectation that the net out-migration experienced during the last 14 years will be reversed in the near future because of the employment opportunities that exist here relative to the rest of the U.S.

Following the growth in resident population, the number of households is projected to grow by 1.4 million to 6.0 million in 2000--an annual rate of 1.6 percent. Average household size is expected to decrease from 2.73 in 1984 to 2.36 at the end of the forecast period.

B. Employment

Total employment in New England is projected to increase by more than 1.2 million jobs between 1984 and 2000. The manufacturing sector is expected to provide nearly one-fifth of the employment growth. On an annual basis, manufacturing employment is forecasted to grow at a rate of 0.9 percent per year which is significantly above what was achieved in the 1970-1984 period (see Exhibit III-3). Particularly strong growth is projected to occur among New England's "high technology" industries (SICs 35-38) where 219,000 new jobs are expected to be created during the forecast period. Employment growth within these industries is anticipated to be 1.8 percent per year 1984-2000. On the other hand, employment in traditional nondurable sectors such as food, textiles, apparel and leather is projected to decline by 49,000 jobs--an annual rate of -1.7 percent.

As shown in Exhibit III-4, nonmanufacturing employment growth is forecasted to be less than the region's historical experience. Employment is expected to grow at an annual rate of 1.5 percent compared to a 2.3 percent growth rate achieved during 1970-1984. Fastest growing sectors are projected to be: finance, insurance and real estate (1.9 percent); government (1.9 percent); and services (1.6 percent).

Labor force growth is expected to closely follow total employment growth. For the entire forecast period. New England's unemployment rate is projected to remain below that of the U.S. Indeed, on an annual average basis, it is expected to be 4.5 percent whereas the national rate is projected to be 7.0 percent.

EXHIBIT III-1

Cumulative Growth in Resident Population

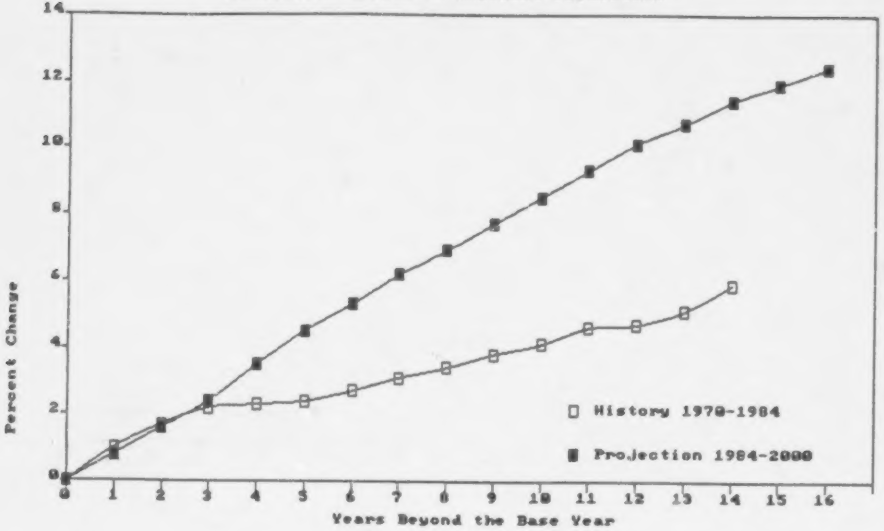


EXHIBIT III-2

Cumulative Growth in Real Personal Income

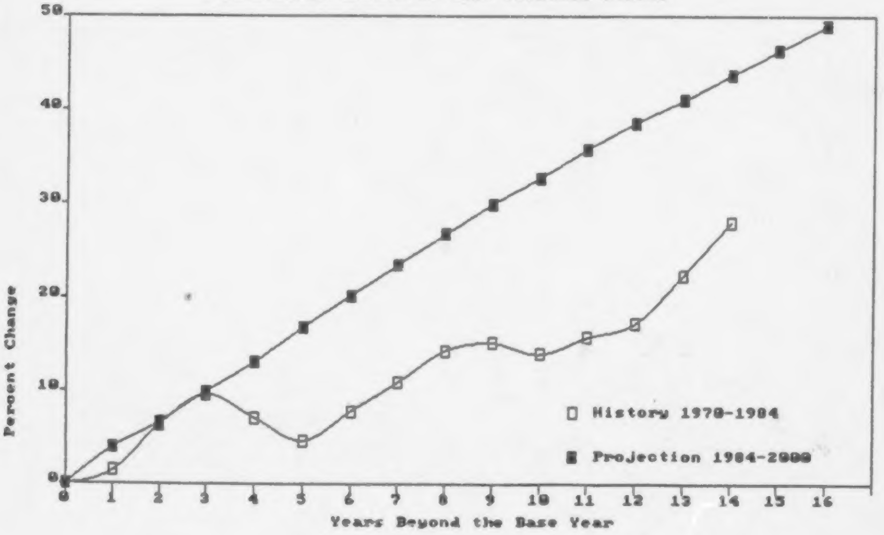


EXHIBIT III-3

Cumulative Growth in Manufacturing Employment

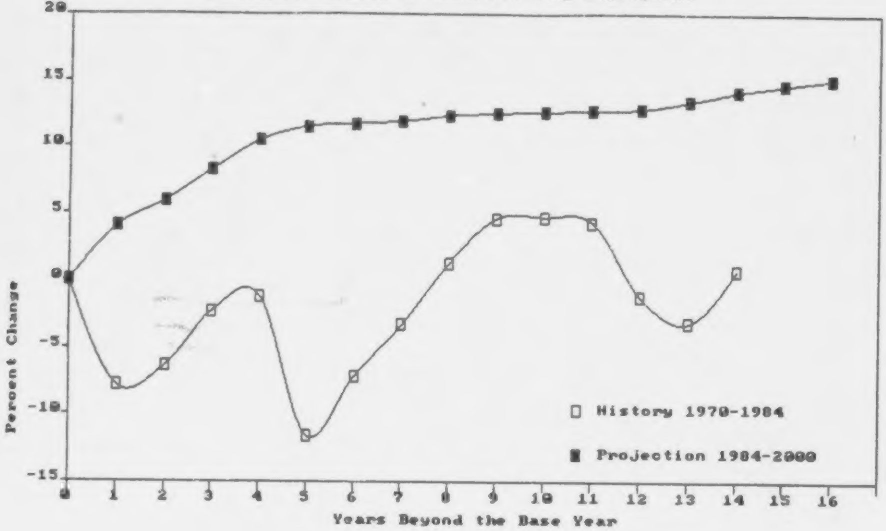
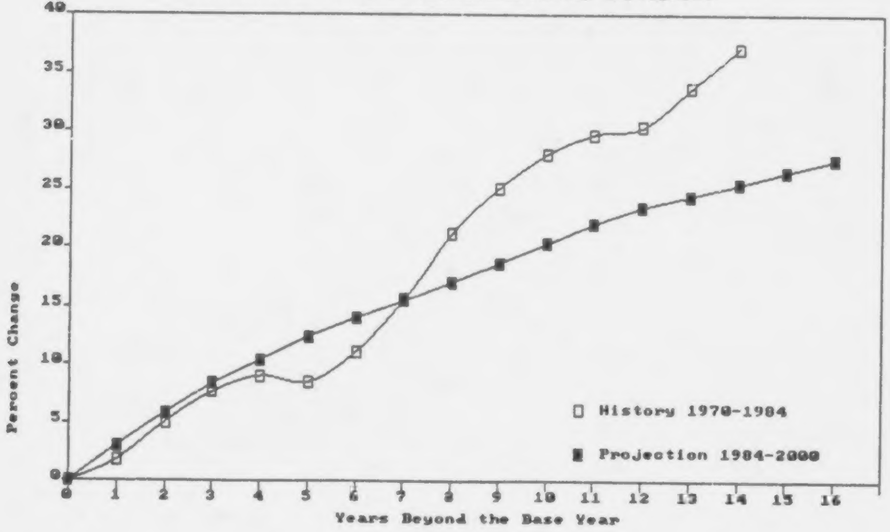


EXHIBIT III-4

Cumulative Growth in Nonmanufacturing Employment



C. Personal Income

Given the tight labor market in the region, it is not surprising that growth in total personal income is projected to exceed that experienced 1970-1984 (see Exhibit III-2). Personal income (constant 1979 dollars) is expected to increase from $122.3 billion in 1984 to $182.3 billion in 2000; this represents an annual growth rate of 2.5 percent. Real personal income per household is projected to rise from $26,500 to $30,400 for an annual growth rate of 0.9 percent.

IV. NEW ENGLAND PEAK LOAD AND ENERGY FORECAST

This chapter presents key components of the forecast of seasonal peak loads and annual energy. Supplementary information such as load characteristics is included in order to facilitate a more comprehensive understanding of the forecast.

A. Winter and Summer Peak Loads

Exhibit I-1 summarizes the New England peak load and energy forecast. Summer peak is expected to rise from its 1984 level of 16,356 MW (16,300 MW weather-corrected) to 22,665 MW in 2000 for an annual growth rate of 2.1 percent. The current projection calls for less-than-historical growth (see Exhibit I-2) for two primary reasons: the long-term impact of significant electricity price increases in recent years and the implementation of load management practices during the forecast horizon.

Winter peak is projected to grow at a rate of 1.7 percent per year over the period--increasing from 17,052 MW (16,900 MW weather-corrected) in 1984/85 to 22,259 MW in 2000/01. Besides the anticipated impact of load management and real price increases, winter peak load growth is affected by an expected moderation in fuel oil prices through the rest of this decade making electricity less competitive as a space heating source.

Load management by the year 2000 is expected to reduce the winter peak by 1,053 MW and the summer peak by 1,016 MW. These magnitudes represent significant increases from 1984 levels of approximately 310 MW for the winter and 140 MW for the summer. Most of the gains result from increased utilization of storage space and water heating systems and controlled office cooling.

B. Annual Energy Sales

The long-range forecast calls for total energy sales to grow at an annual rate of 2.1 percent. Exhibit IV-1 compares the projected growth with that experienced during 1970-1984 (annual growth of 3.1 percent). Lower rates of growth are likewise forecasted for the residential and commercial classes, while the industrial class is expected to increase at a somewhat faster than historic growth rate (see Exhibits IV-2 to IV-4).

C. Residential Use

Residential sales rise from 31,200 GWh in 1984 to 42,560 GWh in 2000, an annual growth rate of 2.0 percent. Fully 80 percent of the growth in the residential class is due to customer growth alone. During the forecast period, the number of households increases at an annual rate of 1.7 percent while average kWh consumption per household grows by 0.3 percent. Exhibit IV-5 shows average residential usage per household 1970-2000; the dip which occurs after 1985 reflects the anticipated consumer response to increases in the price of electricity (see Chapter II).

EXHIBIT IV-1

Cumulative Growth in Total Energy Sales

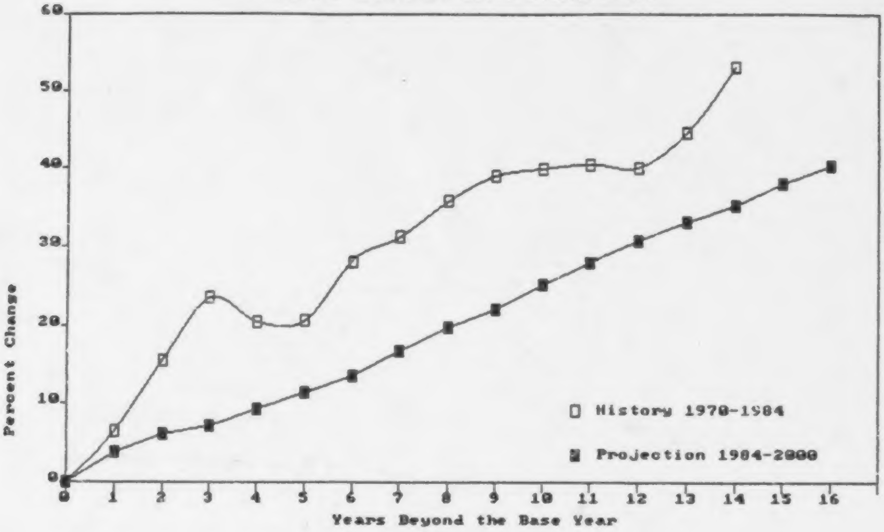


EXHIBIT IV-2

Cumulative Growth in Residential Energy Sales

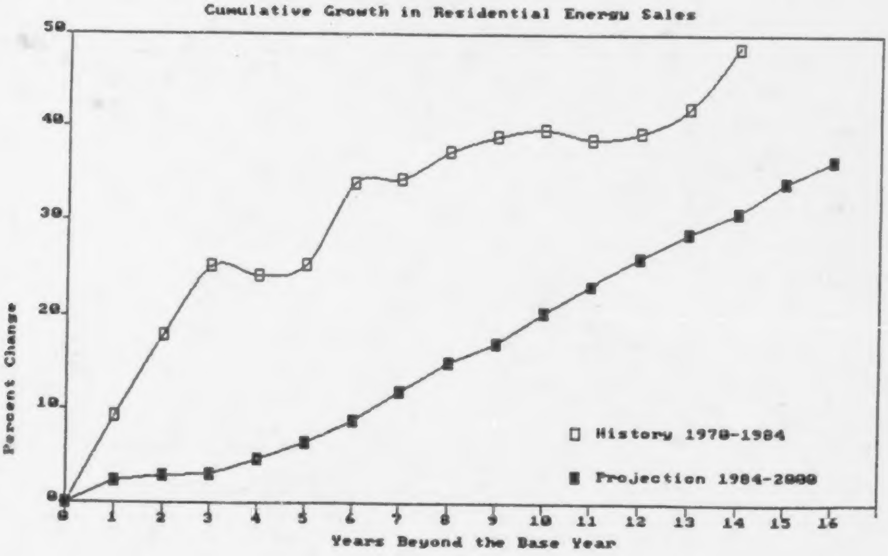


EXHIBIT IV-3

Cumulative Growth in Commercial Energy Sales

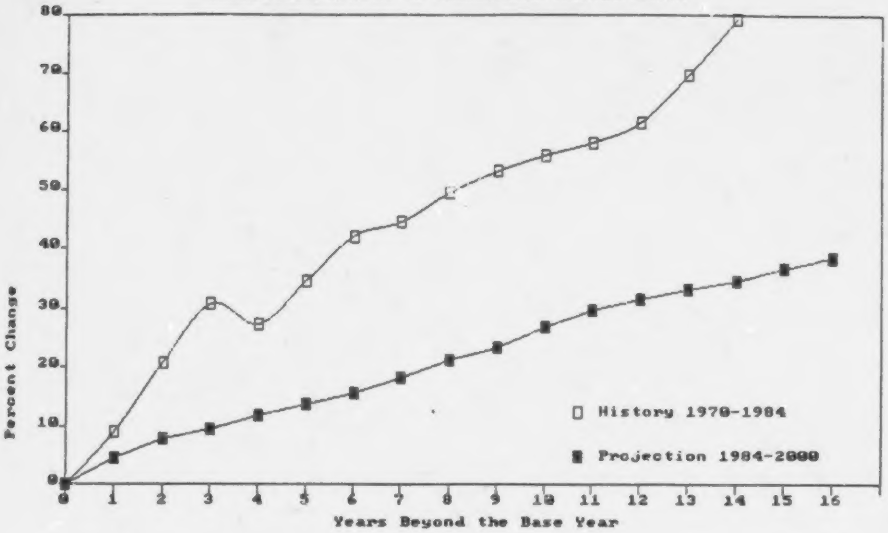


EXHIBIT IV-4

Cumulative Growth in Industrial Energy Sales

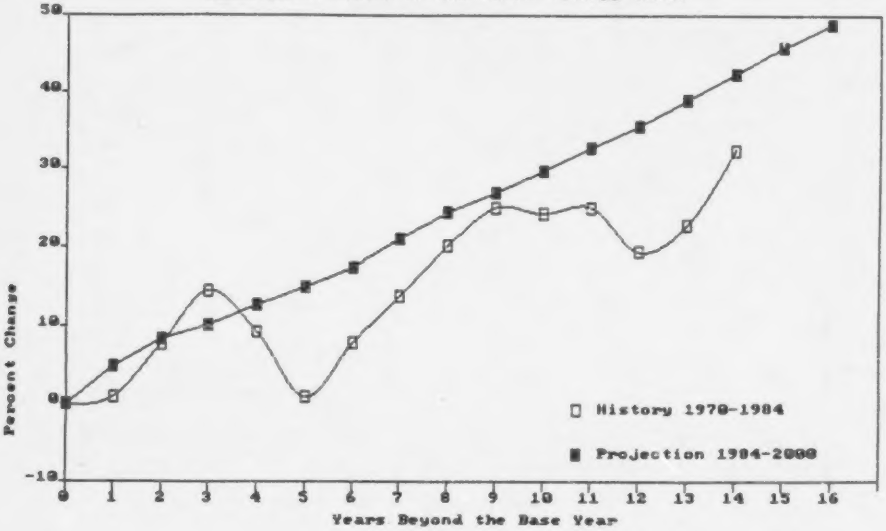


EXHIBIT IV-5

Residential KWH Per Household

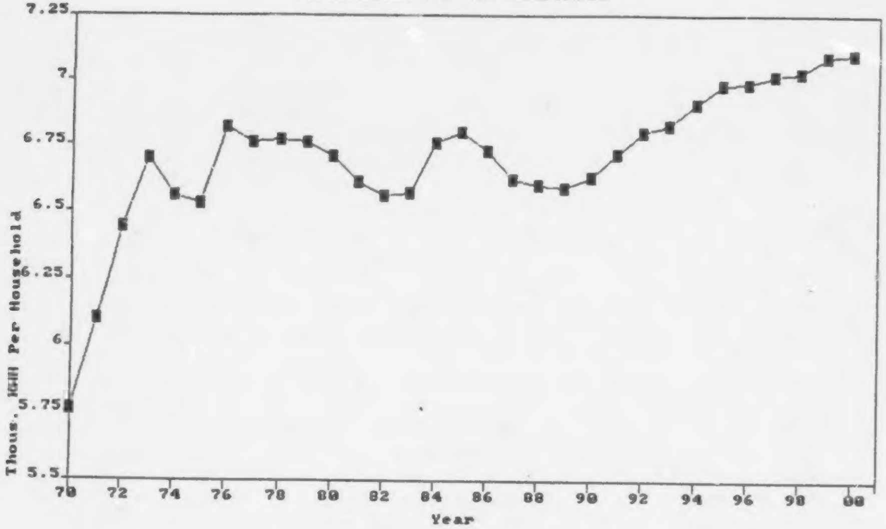
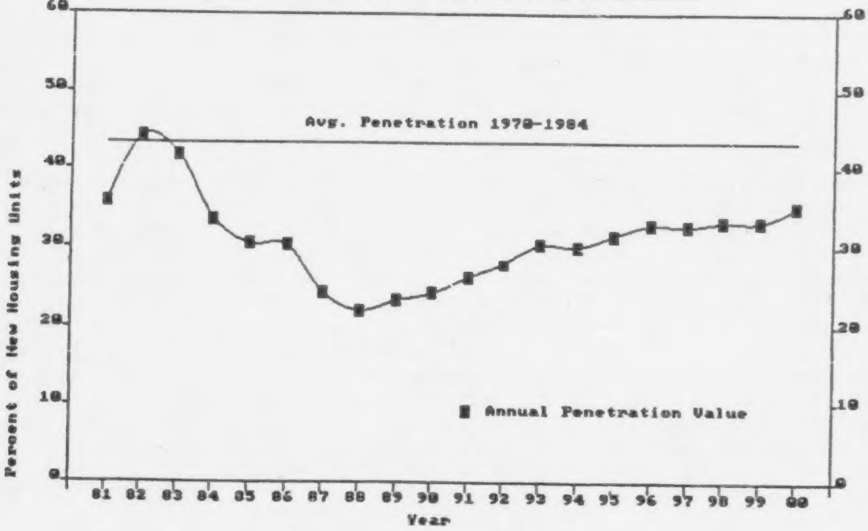


EXHIBIT IV-6

Residential Electric Space Heating Penetration



The end-use components exhibiting the fastest growth within the class are air conditioning (3.5 percent), water heating (3.1 percent) and television (2.5 percent). Over the forecast horizon, the total number of room air conditioners is projected to increase by 89 percent, or 2.6 million units. A strong demand for central air conditioners is also expected. Sixteen percent of all households are projected to have central air conditioning by 2000. Primary factors responsible for this growth are increases in real personal income per household and overall growth in the number of customers. Air conditioners in the year 2000, however, are expected to be more efficient than their counterparts in 1984. For example, the average room air conditioner is estimated to have consumed 250 kWh in 1984; average usage per unit in 2000 is projected at 200 kWh. In total, residential air conditioning sales are expected to rise from 980 GWh in 1984 to 1,700 GWh at the end of the forecast period.

Electric water heaters are projected to be installed in 47 percent of the new housing units constructed during the next 15 years--achieving a 32 percent saturation. The composition of electric water heaters in 2000 will be quite different from today's circumstance. It is expected that 64 percent of installed units will be controlled storage systems with no electrical demand during weekday hours ending 8:00 a.m. through 8:00 p.m. Thus, while electric water heater consumption increases from 5,830 GWh in 1984 to 9,480 GWh in 2000 (by more than 60 percent), their contribution to peak load is projected to decrease (see discussion in Section IV-G).

The number of television sets in New England is forecasted to increase by 6.6 million (3.6 percent per year). Energy sales associated with this end-use are expected to grow from 3,550 GWh in 1984 to 5,240 in 2000. Like air conditioning, increases in real personal income and the number of households are expected to encourage growth in this residential end-use.

Conspicuously absent from the above list of residential growth leaders is electric space heating. Total space heating sales are forecasted to increase by only 0.8 percent per year, from 3,320 GWh in 1984 to 3,780 GWh in 2000. It is projected that on average only 29 percent of all new housing units constructed will select electric heat (see Exhibit IV-6). By comparison, during the 1970-84 period, a 44 percent penetration rate was achieved. The poor performance of electric space heating in the marketplace is attributable to anticipated moderation in residential fuel oil prices combined with the expected real increases in the price of electricity. Of the new electric heating systems installed during the forecast horizon, nearly 52 percent are projected to be controlled storage space heaters and 47 percent are expected to be heat pumps.

D. Commercial Use

Historically, the commercial sector has been the fastest growing class of energy consumption. During the post-embargo period 1974-1984, commercial energy sales grew at an annual rate of 3.4 percent. This forecast calls for the commercial class to increase from 29,630 GWh in 1984 to 41,410 GWh in 2000 for an annual rate of 2.1 percent. The anticipated growth rate is lower primarily for two reasons: the expectation of slower employment growth and the impact of increases in the price of electricity.

Commercial employment is projected to increase at a rate of 1.5 percent per year. Historically, employment growth was nearly a full percentage point higher. The slower growth reflects a general slackening in the long-term trend towards a more service-oriented economy and an expectation of improved productivity in the commercial sector.

The fastest growing sectors in terms of energy usage are finance, insurance and real estate (2.6 percent), government (2.4 percent) and services (2.3 percent). Exhibit IV-7 shows the projected annual kWh per employee for the entire class. While the saturation of electric space heating rises from 12 to 17 percent and that of air conditioning increases from 60 to 68 percent, the average employee is forecasted to consume only 10 percent more kWh at the end of projection period than in 1984. By contrast, average kWh per employee in 1984 was 30 percent greater than the 1970 ratio.

E. Industrial Use

Energy sales to the industrial sector are projected to increase from 22,800 GWh in 1984 to 33,920 GWh in 2000 for an annual growth rate of 2.5 percent. A comparable rate of growth was achieved during the 1976-1984 period.

Driven by a continuing international demand for computers, electrical components and defense equipment, about 55 percent of the increase in sales is attributable to growth in New England's "high technology" sector (SICs 35-38). Sales to this industrial category are forecasted to grow at a rate of 3.6 percent per year (see Exhibit IV-8).

By contrast, combined sales to all other manufacturing industries are expected to increase at an annual rate of 1.8 percent. Growth leaders among these latter industries are rubber and plastics (3.1 percent) and paper products (2.6 percent). Paper products is expected to remain New England's most important industry--maintaining its 18 percent share of total industrial sales throughout the forecast period.

F. Miscellaneous Use

Miscellaneous energy use accounted for approximately 1.5 percent of total energy use in 1984. This sector is expected to grow at an annual rate of 0.4 percent from its 1984 level of 1,270 GWh to 1,350 GWh in 2000.

Streetlighting, which accounts for about 70 percent of miscellaneous energy use, is expected to grow at an annual rate of 0.6 percent. This increase reflects growth in the New England population whose impact is somewhat lessened by the results of utility-sponsored re-lamping programs. Farm equipment energy use is projected to decline by 0.3 percent per year.

EXHIBIT IV-7

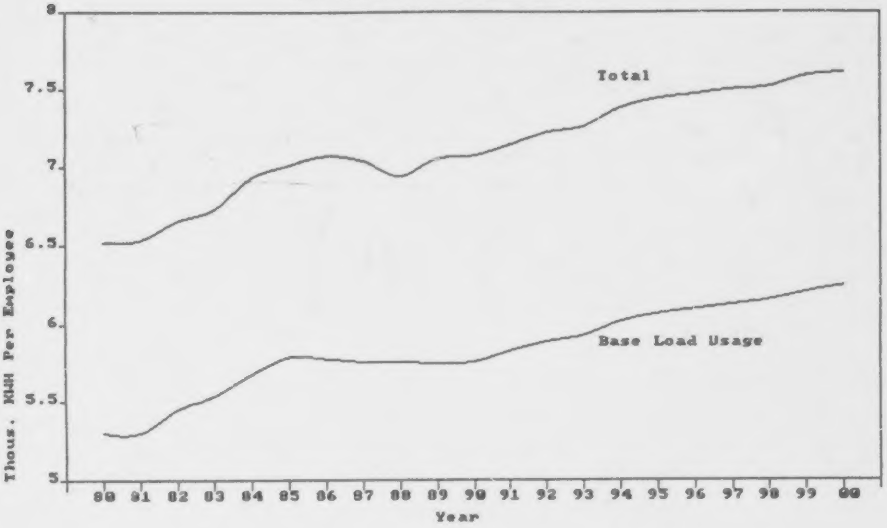
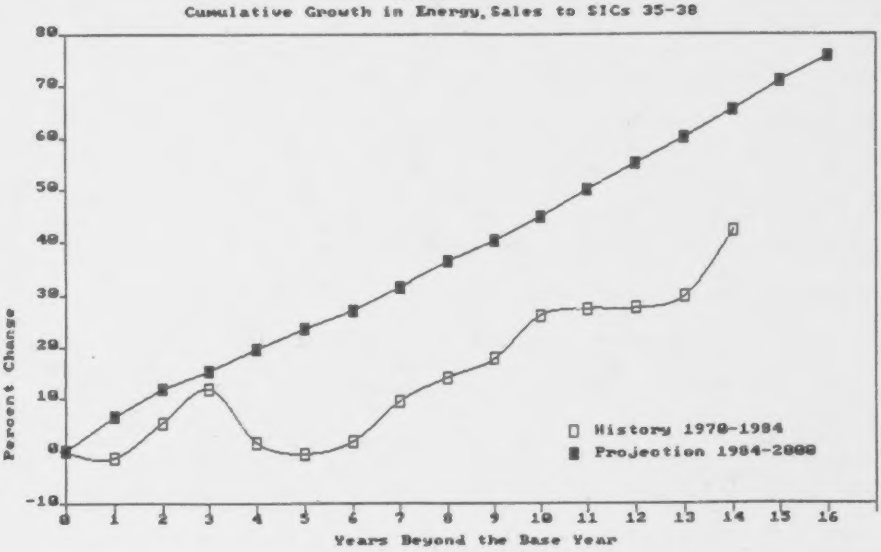


EXHIBIT IV-8



G. Seasonal Peak Load and End-Use Components

Exhibits IV-9 through IV-12 depict individual class contributions to summer and winter peak load 1985-2000. The relative importance of the commercial (including miscellaneous) class to peak demand can be seen to be significantly greater than its share of total energy sales. Growth in this class accounts for 45 percent of the projected increase in winter peak load and 37 percent of summer peak load. The commercial class contribution to the summer peak is reduced by approximately 220 MW by the end of the forecast period as controlled office cooling is instituted as a load management option.

Individual end-use components of peak load are shown in Exhibit IV-13. It is to be noted that the contribution of residential water heating to the seasonal peak loads declines in absolute terms because of company load management programs related to the installation of controlled storage water heaters. Similarly, total residential space heating load declines due to the adoption of storage space heating systems. Exhibits IV-14 and IV-15 highlight the difference between the residential load profile with and without load management in 2000.

EXHIBIT IV-9

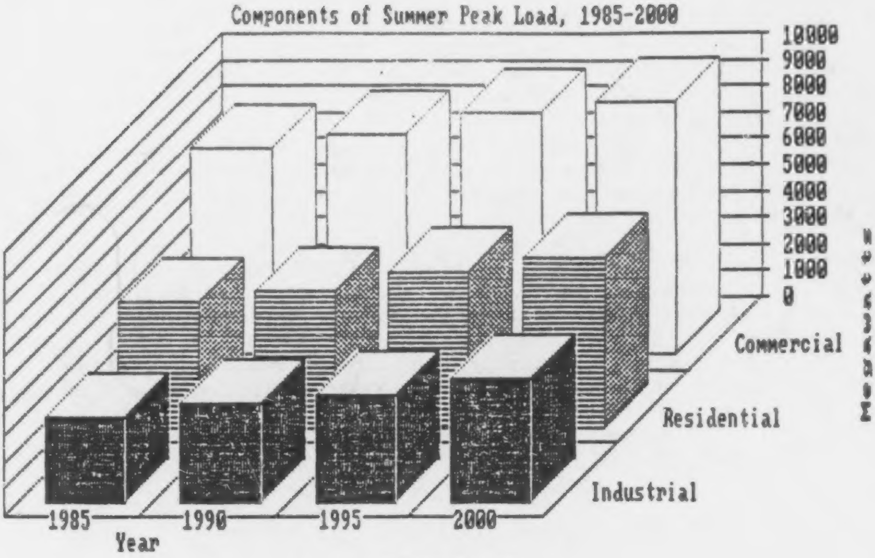


EXHIBIT IV-10

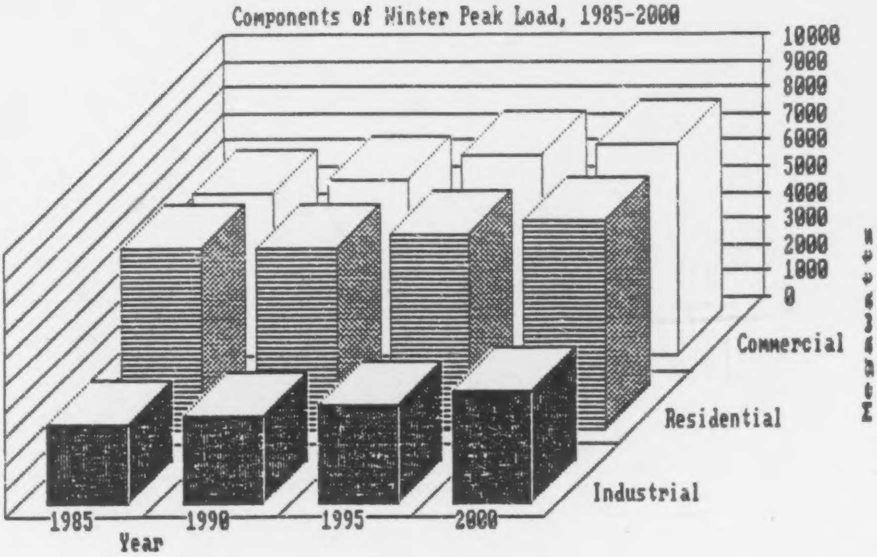


EXHIBIT IV-11

Summer Peak Day Load Profile by Class, August 2000

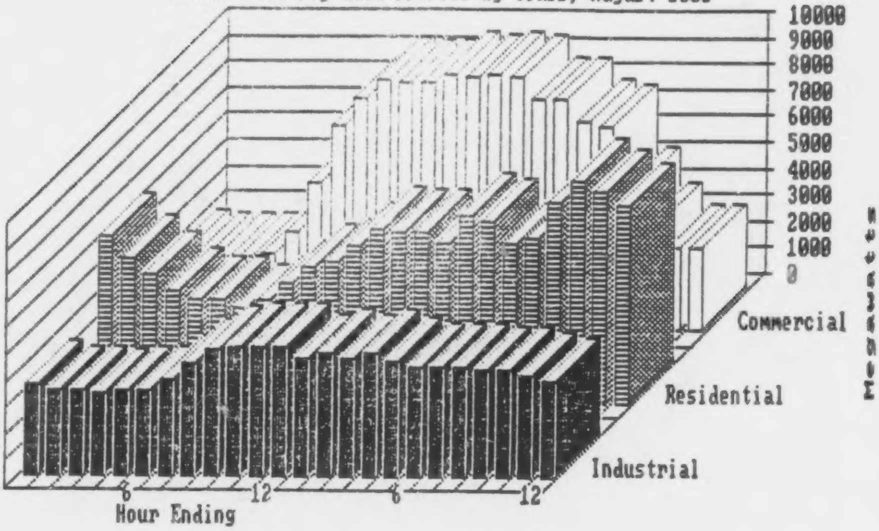


EXHIBIT IV-12

Winter Peak Day Load Profile by Class, Dec. 2000

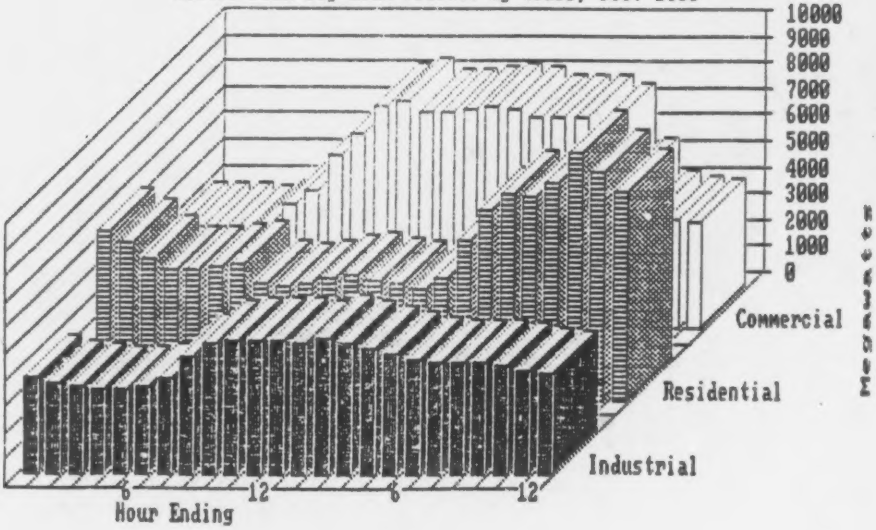


EXHIBIT IV-13
END-USE COMPONENTS (Megawatts) OF SEASONAL PEAK LOAD, 1985 AND 2000

	Summer		Winter	
	1985	2000	1985/86	2000/01
System Peak Load	17,189	22,665	17,518	22,259
Time of Occurrence*	Aug.,TU,1 p.m.	Aug.,TU,2 p.m.	Dec.,TU,7 p.m.	Dec.,TU,7 p.m.
Residential	4,761	6,494	6,854	7,915
Cooking	256	311	626	767
Refrigeration	747	914	644	744
Freezers	210	261	168	198
Clothes Dryers	321	336	298	388
Water Heating	430	343	523	403
Television	466	631	1,052	1,549
Lighting	111	127	1,336	1,357
Air Conditioning	1,739	2,817	0	0
Space Heating	0	0	1,519	1,472
Other Residential	480	755	689	1,036
Commercial & Misc.	7,777	9,589	6,117	8,055
Base Load	4,674	6,323	4,463	5,865
Air Conditioning	3,071	3,235	0	0
Space Heating	0	0	1,343	1,868
Streetlighting	0	0	236	252
Farm Equipment	31	31	75	71
Industrial	3,243	4,641	2,967	4,273
SIC26 Paper	448	639	500	716
SIC28 Chemicals	198	224	186	214
SIC30 Rubber & Plastics	206	292	218	327
SIC33 Primary Metals	200	267	205	271
SIC34 Fabr. Metals	234	328	194	281
SIC35 Nonelect. Machinery	396	991	360	850
SIC36 Elec. Machinery	500	672	428	596
SIC37 Transportation Equip.	244	336	249	350
SIC38 Instruments	120	173	119	175
Other Manufacturing	697	719	509	493
System Losses	1,412	1,942	1,589	2,016

*TU refers to daytype Tuesday-Friday; the hour of occurrence indicated is for hour ending.

EXHIBIT IV-14

Residential Class Contribution to Peak, Aug. 2000

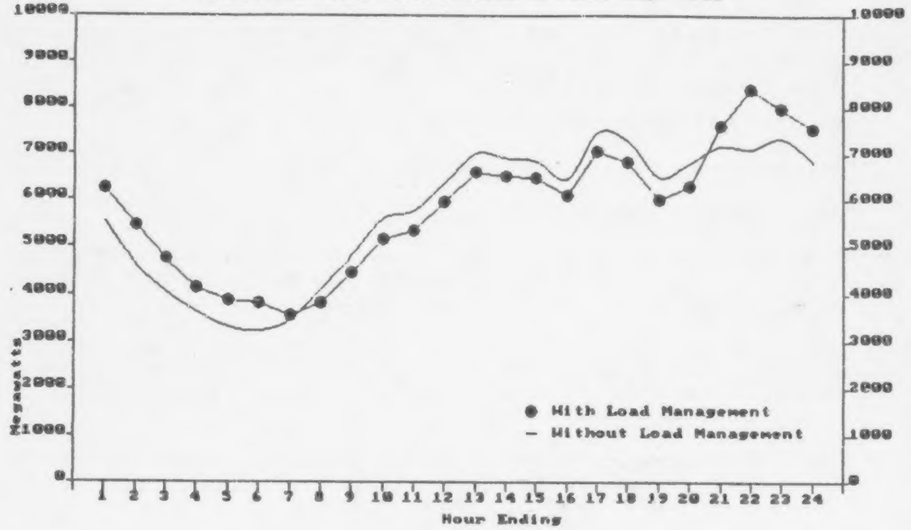
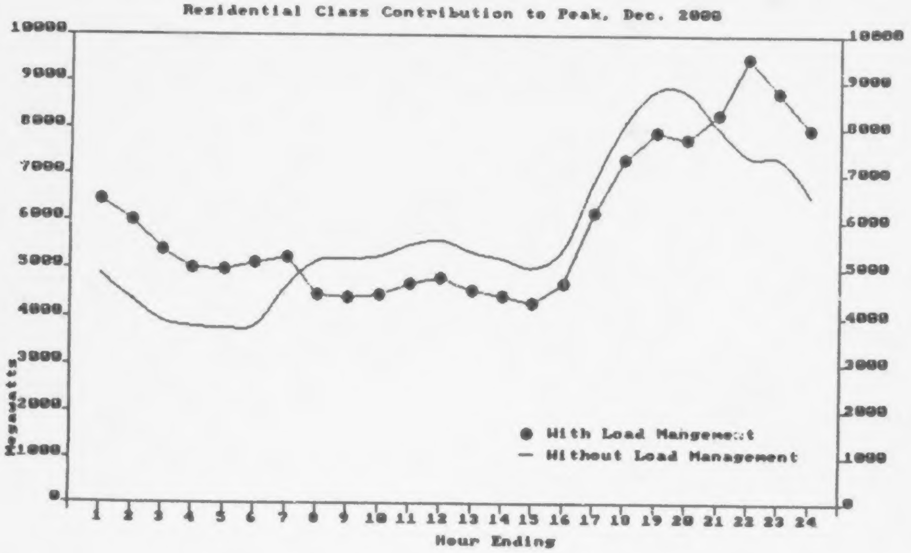


EXHIBIT IV-15

Residential Class Contribution to Peak, Dec. 2000



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APPENDIX III

Northeast Utilities (NU), a registered holding company, furnishes electric service to more than 1.2 million customers over an area covering 5,882 square miles in 208 cities and towns in Connecticut and western Massachusetts through three wholly owned subsidiaries; The Connecticut Light and Power Company (CL&P), Western Massachusetts Electric Company and Holyoke Water Power Company.

CL&P also furnishes retail gas service to approximately 158,000 customers in an area covering about 1,322 square miles in 53 cities and towns in Connecticut.

In 1984, NU met its customers electric energy requirements with a generation mix of 57 percent nuclear, 25 percent oil, 12 percent coal (including purchases from other utilities), 4 percent hydroelectric, and 2 percent natural gas.

The **Chairman**. Thank you very much.

Mr. White.

STATEMENT OF W. S. WHITE, JR., CHAIRMAN AND CHIEF EXECUTIVE OFFICER, AMERICAN ELECTRIC POWER CO., INC.

Mr. **White**. Thank you, Mr. Chairman.

My name is W. S. White. I am chairman and chief executive officer of American Electric Power Co. We're a public utility holding company with headquarters in Columbus, Ohio, and I am very pleased for this opportunity to appear before the committee this morning and to give my views on the outlook for our Nation's future electric power supply.

By way of background, the eight operating companies of the American Electric Power system provide service in parts of seven States. We serve more than 3,100 communities and a population of about 7 million people in the East Central Region of the United States.

In 1984, our system realized a peak demand of more than 20 million kilowatts, and we supplied an aggregate load of more than 120 billion kilowatt hours. About 87 percent of that was produced in coal-fired plants, and the remainder in the main was from nuclear energy.

The AEP system has one of the strongest, if not the strongest transmission systems in the world, with 111 direct high voltage interconnections, with 27 unaffiliated neighboring power systems in 10 states around us. For many years, the system has been carrying out a variety of power interchange transactions involving sales and purchases of electric power and energy with our neighbors on a continuous, day to day basis.

Now we built the generating capacity of the AEP system, planned it and built it, for the sole purpose of meeting the electric power needs of our own internal customers. However, there is some capacity that is available from time to time to other utilities during periods when it can be spared for meeting our customers needs. During 1984, we supplied more than 31 billion kilowatt hours of electric energy to neighboring utilities, a good part of that being used to displace high cost oil fired or gas fired generation on some of our neighboring utility systems.

Our experience shows that the greatest impact on society's needs for electric power and energy comes from the basic ebb and flow of economic activity. A good deal has been written in recent years about the decoupling of energy usage from the gross national product index, but I think as several have indicated this morning, that while that may be true for total energy, that it is not true for electric energy, and we continue to see a strong correlation between the use of electric energy and the gross national product. That has been true on the AEP system, I think as well as in the whole region that we serve, and indeed in the Nation as a whole.

If high levels of economic activity result in higher levels of electric energy usage, it's logical for us to conclude that a substantial curtailment in electric energy usage through a shortage in generating capacity would result in a substantial reduction in economic activity. Or, to put it another way, if we do not make provision in the next few years to provide for the electric energy requirements which are associated with growth in our economy, then such economic growth as we have is sure to be inhibited.

The adequacy and reliability of electric power supply diminished as a matter of public concern in recent years I think because we have had substantially a reliable electric supply. It's true that there are relatively high generating capacity margins available today on many of the electric utility systems, but I think it would be very dangerous to assume that that state of affairs will continue into the indefinite future.

Today there are powerful regulatory disincentives which have been commented on here this morning, causing the electric utility industry to avoid building major new generating and transmission facilities. The present indications are there's not enough generating capacity and not enough major transmissions facilities will be built in the years ahead to meet the requirements of the next decade and beyond, even if we only have moderate economic growth.

As an example, the electric utilities in the East Central Region of the United States, which is where the AEP system is located, project an increase in demand of close to 13 million kilowatts during the period 1984 through 1985. That's based on an annual average growth rate of 2 percent. Should the actual annual growth rate turn out to be 2.5 percent during that period, the increase in electric demand within the region would be close to 17 million kilowatts.

At the present time, only slightly more than 7 million kilowatts of generating capacity is under construction in that region. Also, of the 105 million kilowatts which is expected to be in service in 1994, about 20 million kilowatts of that will be at least 35 years old by that time. This trend gives us a great deal of concern, because of the long lead times which are associated with the planning, the siting, and the construction of major power supply facilities, and a shortage in such facilities would take years to overcome.

In the meantime, the country would pay the price through inhibited economic growth. An adequate and reliable electric power supply cannot be assured for the 1990's and beyond, we believe, unless the necessary ingredients are woven into the fabric of the Nation's energy program. The cost of electric power must not be suppressed to the point that it prevents the assurance of the availability of such power.

If electric utilities can't earn sufficient return on their investments to enable them to attract new capital, or if the risks associated with investment in new facilities becomes too great, then new power facilities simply won't be built to replace wornout equipment and to provide for new load growth.

Our industry has been severely criticized recently concerning excess generating capacity, and the critics of course have the benefit of hindsight and second-guessing the prudence of decisions made more than 10 years ago in most cases under an entirely different set of circumstances than we have today. But we can just imagine the criticism which would exist today if we were trying to overcome the shortage of generating capacity, rather than a temporary excess.

I share the views that were expressed by some of our colleagues earlier, that a slight excess from the standpoint of the Nation is far better than a slight shortage. Facilities are in place today because they were planned and construction was started on them more than 10 years ago, and if the electric powerplants that need to be available 10 years from now are in place, they will have to be started or planned for start now.

Utility managements and utility investors must have trust in the regulatory compact that is supposed to ensure the opportunity to earn a fair return on their investment in return for a limit on their profits. If that integrity and trust is lost, it will take a very long time indeed to restore it. Should this happen, shortages of electric power supply could well develop. In my view, that would wreak economic devastation on our country.

That, Mr. Chairman, concludes my statement.

[The prepared statement of Mr. White follows:]

STATEMENT
OF
W. S. WHITE, JR.
CHAIRMAN AND CHIEF EXECUTIVE OFFICER
AMERICAN ELECTRIC POWER COMPANY, INC.
BEFORE THE
COMMITTEE ON ENERGY AND NATURAL RESOURCES
OF THE UNITED STATES SENATE
WASHINGTON, D.C.
July 23, 1985

Mr. Chairman, my name is W. S. White, Jr. I am Chairman and Chief Executive Officer of the American Electric Power Company, Inc., a public utility holding company with headquarters in Columbus, Ohio. I am pleased to appear before this committee today and to present my views on the outlook for the nation's future electric power supply.

By way of background, the eight operating companies of the American Electric Power (AEP) System provide electric utility service in parts of seven states, serving more than 3,100 communities and a population of about seven million people in the East Central region of the United States. During 1984 the AEP System reached a peak demand of more than 20 million kilowatts and supplied an aggregate load of more than 120 billion kilowatthours. About 87 percent of the electric energy generated by AEP System power plants was produced from coal, with most of the remainder coming from nuclear energy.

The AEP System has one of the strongest, if not the strongest, transmission networks in the world and has 111 direct high-voltage interconnections with 27 unaffiliated, neighboring electric power systems in ten states. For many years, the AEP System has been carrying out with its neighboring utilities -- on a continuous, day-to-day basis -- a variety of power interchange transactions involving sales and purchases of electric power and energy.

While all the generating capacity on the AEP System has been planned and built for the sole purpose of meeting the electric power and energy requirements of the AEP System's own internal customers, some of such capacity is being made available to other electric utilities during periods when it can be spared from meeting AEP's own needs. During 1984, the AEP System supplied more than 31 billion kilowatthours of electric energy to neighboring utilities. A substantial part of that energy was used to displace high cost, oil-fired or gas-fired generation on neighboring utility systems.

Based on AEP System's first-hand experience, there is no doubt in my mind that the basic ebb and flow of economic activity has -- by far -- the greatest impact on society's requirements for electric power and energy. While much has been made in recent years of the alleged "decoupling" of electric energy usage from the gross national product index, the facts -- certainly in the instance of the AEP System -- do not support this theory. The close correlation between the growth in economic activity and the growth in electric energy requirements can be readily seen, in the instance of the AEP System, from the following relationships: During the periods 1960-1973, 1973-1982, and 1982-1984 the rates of growth in GNP, in constant 1972 dollars, were 4.2 percent, 1.9 percent, and 5.2 percent; the corresponding rates of growth in AEP System's energy requirements during each of these periods were 6.9 percent, 0.6 percent, and 5.4 percent, respectively.

If higher levels of economic activity result in correspondingly higher levels of electric energy usage, it stands to reason to conclude that a substantial curtailment in electric energy usage -- because of a shortage in generating capacity -- is bound to result in correspondingly substantial reduction in economic activity. Put another way, if provision is not made for the electric energy requirements associated with future growth in our economy, such growth is sure to be inhibited at best.

While the adequacy and reliability of electric power supply, as an area of public concern, has receded into the background in recent years -- twenty years after the Northeast Blackout and in view of relatively high generating capacity margins being available today on most electric utility systems -- it would be very dangerous to assume that this state of affairs is likely to continue indefinitely. Rather, all indications are that -- as the result of powerful regulatory disincentives to build new major generating and transmission facilities that are impacting the electric utility industry today -- not enough generating capacity and not enough major transmission facilities will be built in the years ahead to meet the requirements of the next decade and beyond, even assuming a moderate economic growth.

The electric utilities within the East Central region, of which the AEP System is a part, project an increase in demand of about 12.9 million kilowatts during the period 1985 through 1994, assuming an average annual growth rate of about 2 percent. Should the actual annual growth rate turn out to be -- say -- 2.5 percent during that period, the electric demand within the region would increase by close to 17 million kilowatts. By way of a comparison, only slightly more than 7 million kilowatts of generating capacity is actually under construction in the East Central region today. Also, about 20 million kilowatts of the region's aggregate generating capacity of 105 million kilowatts expected to be in service in 1994 will be at least 35 years old by that time.

Unless this trend is checked and then reversed, our country is bound to find itself -- just a few years hence -- with inadequate power supply resources to sustain the continuation of its economic growth. Because of long lead times associated with the planning, siting, and construction of major power supply facilities, any shortages in such facilities -- once brought about -- would take many years to alleviate. In the meantime, the country would be compelled to suffer the then unavoidable consequences of an energy-limited economy.

The adequacy of electric power supply will not be assured during the 1990's and beyond unless the necessary ingredients are woven into the fabric of the nation's energy program. The cost of electric power must not be held so low as to prevent, in fact, the assurance of the availability of such power. If electric utilities in this country are prevented from earning sufficient return on their investments to enable them to attract new capital

-- or, if the risk associated with investment in new power supply facilities becomes too great -- new power supply facilities just will not be built to replace worn-out equipment and to provide for new load growth.

The industry has been severely criticized recently on the so-called "overcapacity" situation with increasingly prevalent governmental and regulatory second guessing, with the benefit of hindsight, of electric utility managements' decisions made many years before under an entirely different set of circumstances. Few consider that the facilities in place today are there because they were planned and construction started more than ten years ago. Fewer still appreciate the fact that electric power plants available ten years from now have to be planned and started now.

The trust of utility managements in the integrity of their government and the trust of utility investors in the "regulatory compact" that was supposed to assure a fair return on their investment in return for a limit on their profits, once lost, will not be easy to restore.

Should this happen, shortages of electric power supply would have -- in my view -- a devasting impact on this nation's economy.

The CHAIRMAN. Thank you, Mr. White.
Mr. Dahlberg.

STATEMENT OF A.W. DAHLBERG III, PRESIDENT, SOUTHERN COMPANY SERVICES, INC.

Mr. DAHLBERG. Thank you, Mr. Chairman.

Thank you for the opportunity to appear before you this morning as part of this EEI panel to discuss the Southern Electric System with you for just a few minutes. My name is A.W. Dahlberg, and I am president of Southern Company Services, which is a service company subsidiary of the Southern Co.

Southern Company Services provide services to four operating company subsidiaries of the Southern Co. These operating companies are Georgia Power Co., Alabama Power Co., Gulf Power Co., and Mississippi Power Co. Together, these operating companies provide service at retail to more than 2.8 million customers in approximately 120,000 square miles consisting of major portions of Georgia, Central and Southern Alabama, Northwest Florida, and Southeast Mississippi.

Our system presently has more than 28,500 megawatts of generating capacity, with an additional 4,970 megawatts presently under construction. In additiona to our territorial obligations, we have substantial contracts to sell power outside of our territorial system. These contracts mature in the 1990's and will be returned for our domestic use at that time.

If we as a system can complete our present construction program, and if our present forecasts for expected load in our territory are reasonably correct, and if we can extend the lines of our existing units that we presently have, we believe that we will be well positioned for the mid-1990's and even into the late 1990's, but that is a lot of "ifs."

I think a look at our present circumstance and our present actual experience with respect to load growth is instructive. Last year, two of our operating subsidiaries, George and Gulf Power, added more customers than ever in their history. If you look at the demand placed on our system over the last three years, those numbers are also instructive.

The peak demand this summer we've already reached with some 23,700 megawatts, the highest level we've ever had. Over the last three years, rather than looking at percent growth, if you look at megawatt growth and you think about that in terms of units, and then the investment required, those numbers get much larger.

The increases on our system over the past prior 3 years have been a 1,500 megawatt increase in 1983, the equivalent of two major units; the increase in 1984, 700 megawatts, the equivalent of one large unit; and the increase this year over last year of 2,100 megawatts, the equivalent of three new units. The variation from our forecast this year was some 1,400 megawatts from our expectation, for two major units.

So we have had, I guess you could say in terms of comparisons to the industry or our expectations, outstanding growth over that period of time. Our expected growth or our estimated growth is still estimated to be about 2.5 percent. That is for territorial use; that does not include any sales outside of our territory.

The question is whether the variation from our forecast, the increases over our forecast, is a short-term phenonemon, whether it is weather related, or whether it indicates a long-term trend. I don't know. The question is: Is our forecast too low? Will it remain too low? I don't know.

We think we possess good skills at forecasting, as good as anybody in the industry. But despite those skills and despite the fact that our forecast is still 2.5, there is a growing realistic view that when you read the meters and your loads are higher than you estimated, there's some reason to suspect that it might be higher than the 2.5 that we project.

There are a few things that I do know. I do know that those in this industry, many in this industry who have built plants and have completed construction and then have been I guess scrutinized as having overcapacity have been penalized, and they have run the risk of that happening. I do know that in this industry those who have taken the approch of cancelling plants when load expectations did not materialize have also been penalized and not been able to recover their costs.

And I do know that, in view of those load expectations and in view of those risks, it makes it much, much more difficult to start a new unit to meet our requirements for the future. So I, like many of you and those on this panel, share a great concern that there may be shortages in the future. But until a balance between risk and reward can be restored, new plant starts will be much, much more difficult.

Thank you.

[The prepared statement of Mr. Dahlberg follows:]

STATEMENT OF A. W. DAHLBERG, III, PRESIDENT, SOUTHERN COMPANY SERVICES, INC.

BEFORE THE SENATE ENERGY AND NATURAL RESOURCES COMMITTEE
July 23, 1985

My name is A. W. Dahlberg, III. I am President of Southern Company Services, Inc. which is a service company organized under the Public Utilities Holding Company Act to provide services to the operating companies, the common stock of which is owned by The Southern Companies. These operating companies are Alabama Power Company, Georgia Power Company, Gulf Power Company and Mississippi Power Company. Together these four operating companies are informally referred to as the "Southern electric system" and, on a combined basis, serve over 2.8 million retail customers in a 120,000 square mile area consisting of the major portion of Georgia, central and southern Alabama, northwest Florida and southeast Mississippi. These four companies have a total generating capacity of 28,593 megawatts and currently have under construction a total of 4,970 megawatts of new capacity. I am appearing as a part of a panel of representatives of the utility industry sponsored by the Edison Electric Institute. I will be summarizing my comments before the Committee and request that my total written comments be filed and made part of the Committee record on this matter.

In several areas of the United States, electric utilities have been criticized and penalized in recent years because the capacity which has been built to serve the utility's load has exceeded the actual load by more than traditional reserve margins. This criticism and the regulatory action taken has had a punitive effect on utilities and their investors. Notwithstanding this criticism, our nation currently enjoys adequate electric generation resources as a result of these past construction programs. The very practice which is being criticized has led the nation to relax its concern over adequate supplies of electricity. The forces in operation reflect the difference between the short-run views of certain regulators and the long-run views which electric system planners must adopt. The clash of these attitudes in the past threaten to produce shortages in the future.

During the 1960's, the expectation was that electric consumption would follow its historical trend of increasing by more than seven percent per annum, compounded annually. This trend had resulted in the demand for electricity doubling every ten years. Plans were developed to build the generating capacity necessary to meet that demand. Failure to provide the resources to meet this anticipated demand was unthinkable since utilities had a duty to project the needs of customers in the area in which they served and a duty to develop resources to meet that need.

During the 1970's, when the "energy crisis" appeared, an economic down-turn occurred and total energy consumption was depressed. Demand for energy no longer grew at the pace which had been experienced in the 1960's. This was true not only with respect to oil consumption, but also other forms of basic energy usage such as electricity. Plants which were being constructed by electric utilities to meet their expected load were well on their way to completion when this change in trends was realized.

Today, we hear little of an "energy crisis." OPEC is having difficulty maintaining control over production and pricing of oil. Economic conditions in the United States have turned around again and our focus is on growth, not periods of shortages. Energy demand, particularly that of electricity, is again on the rise. In 1972, before the oil embargo, electricity accounted for 26 percent of our nation's basic energy consumption. In 1977, that figure had risen to almost 30 percent. By 1982, more than 34 percent of our basic energy consumption was electricity. The trend established by this data should be viewed with concern, particularly if the impediments to building electric generation facilities which have been developed in recent years are permitted to continue, and if new impediments are developed to frustrate further the effort.

I. Expected Demand for Electricity in the Southern Electric Systems' Service Areas: Load forecasting in our region has been a difficult task over the past several years. We are located in an area that is part of the so-called "sun belt" which has been projected by many to have the greatest economic growth in the nation. Yet there are certain areas within our region which have experienced high unemployment and which have not shared in the economic recovery of recent years. Load forecasting for electric utilities is, at best, an inexact science impacted by the same economic contingencies which face all businesses when they plan for the future. Forecasting of demands by electric utilities is even more difficult than in other businesses for the following reasons: (1) Demand for electricity is extremely sensitive to changes in government policies--that is, loads will either appear or disappear because various governmental agencies act or fail to act. I will discuss some aspects of this sensitivity below. (2) Forecasts of electric demand must be made eight to fourteen years in advance because generation plant construction periods have grown to this length. (3) In addition, the task is more burdensome because of the awesome consequences which flow from missing the forecast on the low side. In such event, society must get by with inadequate supplies of electric power. The consequences to society of missing estimates on the high side are not as great; however, the results of such a miss may be devastating to the utility.

A. Load Forecasting: The lack of precision in load forecasting can be seen in the drastic changes which were made in the estimated ten year annual growth rates projected over the period of the early 1970's to date. These growth rates changed dramatically because of changed economic conditions and changed government policies.

We have found that demand for electricity is more sensitive to governmental policy changes than we would have expected fifteen years ago. We have always recognized that electric demands were closely tied in with general economic conditions. We also found during the last decade that various government policies impacted electric usage to a great extent. For instance, electric demand was very sensitive to government positions relating to foreign imports. Moreover, the residential market for electricity had seen very little evidence of price elasticity until the drastic price increases experienced during the 1970's. These price increases were due in part to general inflation; however, a major reason for the increases related to government policies requiring increased pollution control, increased regulation of coal mining (for both environmental and miner safety reasons) and increased regulation of nuclear plant construction activities. I am not criticizing these policies as undesirable. I am merely pointing out that these policies did have an impact on demand which could not have been foreseen, just as we cannot now see what changes in electric demand will occur in the 1990's as a result of governmental policies not now in place.

The radical change which occurred over the past twelve years can be seen from the following table:

Year of Projection	Projected Growth Rate
1973	9.0%
1975	8.9%
1977	6.6%
1980	3.6%
1984	2.4%
1985	2.5%

It seemed impossible in 1973 that the expected growth rate would not be achieved. Likewise, I would tell you today that it would be improbable that the growth rate which we are currently projecting will be exceeded. Yet, having done our best to look into the future and project the loads, we all must recognize that questions will always exist as to the accuracy of any forecast.

A comparison of the last four years' actual demands with those which were projected reveals that the loads were greater than had been expected. This phenomena is reflected in the following table of territorial loads (which do not include the system's commitments to off-system customers):

Year	Forecast	Actual	Percent Variation
1985	22341	23740 (year to date)	+6.3%
1984	20922	21618	+3.3%
1983	20682	22131	+7.0%
1982	20541	19532	-4.9%

The significance of these statistics is more concrete when one recognizes that the Southern electric system's June 1985 summer peak (to date) exceeded the previous years' summer peak by over 2,100 MW. That is the equivalent of three large central station generating units. While one may tend to minimize this statistic as weather related - that is, a result of an extremely hot summer - you must recognize that we must have electricity available to meet the extreme situation, not just the average conditions.

Are these short-run phenomena reflective of a long-run trend? These variations which have been experienced over the past decade, as well as the last three years, have led us to recognize that point forecasting is bound to be wrong and that one should strive to define a band of growth rates within which actual loads will probably fall. Having drawn that conclusion, however, one must acknowledge that the consequences of planning resources to serve a range of possible growth rates is staggering. For instance, within the area served by the Southern electric system companies, a one-half percent difference in growth rate over a ten year period is the equivalent of a complete powerplant which takes ten to fifteen years to build and $4 billion to complete.

B. Consequences of Load Forecasting: Given the difficulty inherent in forecasting electric demand, one must next examine the consequences of missing the forecast. We have seen in the past few years what happens if you project too high and build plants to meet that expectation. In several states, the response of regulators was that the construction programs should have been abandoned, or never initiated, and the utility and its owners were left twisting in the wind. A variation of this theme has been that if plant construction is initiated when load projections were high, and construction is stopped when economic down-turns are experienced, some utilities have been penalized by not being allowed to recover from its customers the costs of the plant which is cancelled. All of these "hindsight" responses have given utilities tremendous incentives to make conservative estimates of future loads and to reflect the lower end of growth expectations in their current projections.

On the other hand, the consequences of not having enough capacity to meet the load of the 1990's is also great. New capacity cannot be developed overnight to meet the demand for electricity. The most economical plants for meeting new loads all require eight to fourteen years to build. These increased lead times have been the product of increased governmental regulation, and to a lesser extent, increased complexity in technology. For whatever the reason, assurance that the capacity will be available requires considerable anticipation.

If we are unable to build capacity to meet the load of the 1990's, I would not suggest to you that we will experience the cascading outages which completely shut down New York in November 1965. A more likely result will be that the utility will develop programs for rotating load cuts which attempt to spread as equitably as possible the consequences of the inability to meet everyone's load. Certainly, however, the result will not be the same as the failure of long distance telephone companies to anticipate the demand for telecommunications. In that industry, if there aren't enough circuits you are simply unable to place a particular call until later. When the rotating load cuts occur, the refrigerator will not run and the motors will not start the machinery in the factories. The consequences of a short-fall in electric capacity can be drastic.

Studies by the Electric Power Research Institute, Federal and State regulatory agencies and various electric utilities and others have been made which demonstrate vividly that the costs to society of an inadequate supply of electricity are much greater than the costs of an equal quantity of excess generating capacity built to satisfy a load forecast which erred on the high side. Today, however, it would appear that regulators, in certain instances, have adopted philosophies which discourage new construction of generating plants, notwithstanding the high costs which may flow if supplies are inadequate.

C. Current Strategies for Meeting Projections: In view of all these problems of making projections and the consequences associated with the task, the companies in the Southern electric system have adopted a program which is designed to retain the greatest amount of flexibility. In the early 1970's, while faced with projections of constantly increasing demands for electricity, these companies embarked on a course of building generating plants which would use low-sulfur coal. Three new plants were under construction when it was recognized that the load growth in the area served by those companies had not materialized as expected. The companies were faced with the choices of (1) cancelling the plants; (2) slowing down construction or delaying the units until the load materialized; or (3) completing construction and selling the capacity to other utilities in the region until the units were needed to supply native load. This third alternative, which amounted to placing the plants in inventory at little or no cost, was the preferable strategy for the Southern electric system. A marketing program was conducted which resulted in sales of capacity to neighboring utilities which needed coal fired capacity to replace oil and gas fired units as well as to meet new capacity needs.

By building these plants now, the companies in the Southern electric system are well positioned to serve the load which is expected to be experienced in the 1990's if our estimate of the future load is correct. However, if our load grows at 1.0% greater than our current projections (3.5% per year vs. 2.5% per year) by the mid nineties our reserves will be below acceptable levels and by the late nineties they will be at zero. Not many utilities are that fortunate. Plants have been cancelled or placed in mothballs. Those with that experience are extremely reluctant to undertake similar projects. More and more one hears reports that in view of the experience of the past decade, utilities are planning to meet future load growth by shopping around to get needed capacity from others rather than building it themselves. If that is true, the probabilities are that the capacity will not be available to meet the demand. No one will start building billion dollar generating plants as speculative ventures, betting that the market will be there when the plant is finished. The rewards allowed by the regulators in this industry are not high enough to entice that type speculation.

II. Strategies for the Future: In reviewing what the future holds and how to meet that future, the companies in the Southern electric system have concluded that their current strategy of attempting to maintain the maximum flexibility is also the strategy for the future. Load projections may be off target by an amount sufficient to require construction of additional resources in the 1990's in addition to those which we already plan to have available. We are maintaining constant attention to the trends so as to identify as soon as possible whether such resources may be needed.

In order to increase flexibility, we are reviewing a wide range of potential sources of additional generating capability and load control techniques other than the traditional central station power plants. This effort includes:

A. Solar technology. We have promoted in several ways the development of new technology aimed at making solar resources more attractive as a source of electricity for the future at competitive prices. A proposal for a joint venture with Chronar Corp. for the development of a factory in Alabama to produce solar cells is currently undergoing regulatory review.

B. Cogeneration efforts. We have established a task force within the system companies to explore with customers those applications of cogeneration which make sense to the customer and which also are complimentary to our plans for meeting loads in the future. While the Southern electric system companies have no current avoided capacity costs as a result of the installation of cogeneration, we recognize that such resources may be valuable to meet our load requirements in the future.

C. Other Non-Traditional Resources. Our research and development organization, in addition to participating on various projects with EPRI, is continuously engaged in looking at development of other non-traditional resources for production of electricity such as the solvent refined coal project which the Southern electric system has supported at Wilsonville, Alabama, fuel cells powered by methane gas from coal beds and power developed from the tidal forces along the Gulf of Mexico.

We also expect to be able to control our loads more effectively in the future. Toward that end, we are exploring numerous means of promoting load management and conservation. One of our major current efforts is the promotion of the wise use of electricity for residential purposes through our Good Cents Homes Program. This program establishes voluntary standards to assure an energy efficient home design. Through application of these standards, our customers are encouraged to make wise use of electricity and at the same time reduce the overall cost of home heating and cooling.

In pursuing a strategy of flexibility, we have also been exploring the revitalization of generating plants in lieu of retirement of those plants. Normally, a steam electric generating plant is expected to remain in service for 30 to 40 years. If the life of these plants can be extended, an added degree of flexibility can be achieved to permit quicker response to upward changes in electric usage patterns. The advantages of revitalizing old units include making use of existing plant sites and providing resources in the short run at lower costs. The disadvantages include placing the reliability of the electric system at risk by reliance on units which are more than 40 years old; utilizing units with less efficient heat rates to serve loads; and using temporary, stop-gap measures while the cost of new generating plants continue to rise.

While we are pursuing all of these alternatives in order to maintain flexibility, it is apparent to us that in the long run, these resources will not completely replace the need for larger, central station power plants if we are to meet the demand for electricity in the late 1990's. In order to preserve the opportunity for developing these needed resources, impediments which currently exist to the development of such plants must be eased.

III. Impediments to Meeting Future Demand: Perhaps the greatest impediment to meeting the future demand for electricity is the regulatory climate which threatens to penalize utilities which build plants to meet anticipated loads. The penalties for this effort cannot encourage future investment in generating resources. Attraction of capital to fund new generating facilities becomes difficult if the potential reward for investment is refusal by an agency to permit earnings on the investment. The utility industry has a tremendous task ahead of it in persuading state regulators across the country of the need for taking a long-run view as to electric generating capacity.

Other impediments also exist as threats to the ability of electric utilities to meet the demand for electric power in the 1990's. These include:

A. A combination of public reaction and increased government regulation has resulted in making the option of nuclear power practically non-existent for plants not now under construction.

B. Coal-fired plants must be built with expensive equipment to remove sulfur whether or not problems have been directly linked to the emission of sulfur and further legislation to tighten the standards even more has been proposed. With respect to emissions of sulfur oxides as well as any other element, we recognize the desire for a clean environment; however, the urge to regulate should be tempered by demonstration that a real problem exists and that the benefits of regulations equal or exceed the cost.

C. Promotion of cogeneration, while potentially a significant part of the answer to future demands, appears to be an area reserved for companies with no legal duty to serve the public. Contracts can be developed to attempt to assure that the capacity will be available; however, entrusting our nation's energy future to entities which have no duty to serve can be risky. Ownership of these facilities by undercapitalized companies can cause the cogeneration capacity to be unavailable when the demand arises. Arbitrary limitations on participation in ownership of cogeneration facilities by utilities, which do have a duty to serve, do not make sense in this context.

D. New tax reform proposals could result in making more difficult the raising of capital for construction of new plants. The proposed repeal of investment tax credits would have an adverse impact on the ability of the Southern electric system companies and other electric utilities to finance new generating plants. The investment tax credit is a vital source of internal cash flow which is used to finance new plants. If repealed, utilities will have to raise tremendous amounts of additional debt and equity capital to replace this loss of cash flow. This burden will certainly result in increased cost of electricity. On the other hand, the new system for tax depreciation - that is, the capital cost recovery system - which has been included as part of the President's tax reform package, does contain capital formation incentives vital to a capital intensive industry such as ours. We would urge that Congress not alter this feature of the President's package.

E. Current licensees for hydroelectric facilities are threatened with arbitrary loss of their existing resources for meeting their loads in the future. The loss of these resources would take place simply because of the ownership character of competing applicants.

IV. Strategies to Avoid Impediments: There are certainly many impediments to making sure that adequate capacity will be available in the 1990's. One is immediately tempted to suggest that another government agency can step in and sweep away the impediments so as to assure adequate electric supplies in the future. I would suggest, to the contrary, that many of the impediments were created by government agencies and it is not rational to expect that an additional governmental agency would aid in the resolution of the problem. In particular, there is no reason to believe that a government agency would be particularly adept at forecasting future loads. For these reasons, the first and foremost strategy I would recommend would be to avoid the temptation to cure the problem by increased government intervention.

Second, I would suggest that there be reevaluation of the government's position in areas which threaten or impede the development of adequate generating resources. This would include:

(1) Examine the need and desirability for legislation to revive the nuclear option as an energy source in this country.

(2) Clarify laws which appear to demand take-over of hydro resources from current licensees to the detriment of the customers who have paid for those facilities.

(3) Avoid further tightening of emission restrictions until there is a clear demonstration of the problem and that the benefits of regulation equal or exceed the costs.

Third, I would urge that Congress refrain from acting in areas which threaten to make even more difficult the task of developing new generating resources. This would include:

(1) Resist tax reform packages which make raising capital for investment in generating facilities even more difficult than it is presently.

(2) Resist the suggestions being made for Congress to reverse FERC regulations which would allow construction-work-in-progress in the rate bases of utilities.

Thank you for the opportunity to appear before this Committee on this vital issue. I will be glad to answer any questions you may have.

Senator EVANS [presiding]. Go ahead, Mr. Turley.

STATEMENT OF KEITH L. TURLEY, CHAIRMAN AND CHIEF EXECUTIVE OFFICER, ARIZONA PUBLIC SERVICE CO.

Mr. TURLEY. Thank you, sir.

Mr. Chairman, my name is Keith L. Turley. I'm chairman of the board and chief executive officer of Arizona Public Service Co. We are an investor-owned electric utility serving approximately 1.4 million Arizonans or about 45 percent of the State's population.

As a Sun Belt electric utility, we are being challenged as never before. In 1984 we experienced the greatest growth in our company's 100 year history when we added 31,000 new customers, a 6.6-percent increase. Even as I speak today, the demand for energy on our system is reaching all-time highs, already 8 percent greater than 1984.

The fact that we are in a position to accommodate this growth and increased demand is more the result of perseverance, bulldogged persistence and commitment to a growing population, rather than mutual cooperation and understanding between local regulators and the utility.

Fortunately, the utilities in the Western Systems Coordinating Council—that is one of the Nation's electric reliability councils composed of the 11 Western States—fortunately those utilities and those of us in the southern part of the council in the desert Southwest have excess generating capacity at this time, because it was wiser to complete most of our current construction projects rather than abandon them when forecasted growth did not materialize.

We are fortunate to have this excess capacity because the western part of the United States, and particularly my part of the West, continue to grow. The 11 Western States project an annual compounding summer peak growth rate of about 2.3 percent over the next 10 years, while the desert Southwest area, Arizona and New Mexico, projects about a 4.4 percent per year compounding.

So the excess generating capacity assures us of the ability to sustain growth into the mid-1990's, when new sources of generation will be needed. Specifically in the case of my company, we will complete the third unit of the Arizona nuclear power project in 1987, marking the successful addition of approximately 4,000 megawatts of nuclear generating capacity to serve utility customers in Arizona, New Mexico, west Texas, and southern California, who are participants in the Palo Verde project.

With our 1100 megawatt share of the project, Arizona Public Service will not require the addition of any new base load generating resources until 1995. However, with a 10 to 15 year leadtime for planning, designing, and constructing major facilities, we must begin the decisionmaking process now.

Mr. Chairman, the electric utility industry, as we have discussed today, faces a far more complex business environment than ever before. Actions of electric utilities, public debate and important considerations before regulatory bodies face us constantly.

Consumers are insisting not only on public accountability, but also a greater role in the decisionmaking process. Some regulatory agencies are exercising 20-20 hindsight through the vehicle of prudency audits. Historically, utility managements, with the approval of their boards of directors, have normally made all the decisions regarding future energy supplies and investment, and I'm proud of my company's record. We have never failed the people of Arizona.

However, faced with regulatory uncertainty and ratemaking delays, as early as 1982—and I believe I'm the first CEO in the nation to do so—I took the position that I was no longer willing to recommend to my board of directors the launching of any new baseload power projects unless the political, business, labor and consumer interests were in agreement with the need for a new energy supply for a growing Arizona. It is my experience that the construction periods for major facilities, which now extend from 10 to 15 years, are longer than the memories of respective authorities that regulate our industry, leaving hindsight as the measure of the quality of utility management's decisions.

So no longer am I willing to risk the savings of thousands and thousands of investors in the hope that politicians somehow will be supported in their rate decisions in the face of the reality that no one likes higher rates.

So what are our alternatives? Recently, after taking a new look at the long-term future, we adopted a new power supply strategy designed to avoid the financing of any additional base load generating facilities until at least after the turn of the century. Our new power supply strategy is now in place. Our plan is to look beyond conventional energy sources, such as oil, gas, coal and nuclear, and employ renewable sources of energy and other alternatives designed to minimize the need for us to raise new capital.

For example, we are already involved in solar technology and we're going to continue those efforts. We believe that the utilization of thermal storage, some additional hydroelectric pumped storage generation, the development of regional coal plants financed by others, upgrading of existing fossil plants, load management, all these will avoid the need to finance any new powerplants during the next 15 years.

In addition, we will strengthen our transmission interties with other utilities in the West. We will explore investments in cogeneration and turn to the burning of solid waste, sometimes known as garbage.

Some examples of what is going on: APS has taken a leadership role with other desert Southwest utilities in analyzing the economic and system benefits that may result from a major inland transmission intertie between utilities in the Pacific Northwest and the desert Southwest. The potential marriage of Northwest winter peaking utilities and the Southwest summer peaking systems should result in the sharing of the seasonal diversity, thereby eliminating the costs of new generating facilities of as much as 1,000 megawatts on each end of the intertie.

Since this intertie will go through three or four States and may have little or no local benefits, I am sure it will elicit considerable opposition. In order for the utilities to see this concept through to fruition, it will require the cooperation and support of the Departments of Interior and Energy, plus acceptance in principle by local regulatory bodies and the Federal Energy Regulatory Commission.

On another front, there is considerable interest in the West in third party construction and financing of power plants. There are three recent examples I might mention briefly. Bechtel Power Corp., General Electric Co., Combustion Engineering, Public Service Co. of New Mexico, and the Navajo Nation have one project under discussion. The second involves Internorth, Gibbs & Hill, and the Meeker, CO, project.

A third under consideration is Nevada Energy Park by Sierra Pacific Resources. This project envisions a generating station financed and constructed by a consortium of nonutility investors with the anticipation of making bulk power sales to utilities in the region.

Now, underlying my comments today is the fact that the electric utility business is changing. Utility management and regulation must be progressive and flexible to accommodate and lead that change. Our critics, our customers, they want to participate, and we welcome them in an open decisionmaking process.

In summary, there is need for additional power generating facilities for further growth which must be in the planning stages now. There are both traditional and new paths to follow. There are new risks, new technologies, and new innovative financing schemes.

Even more important is the need for regulatory reform at both the State and Federal levels. I do not know of any utility executive who would be willing to commit the enormous financial resources that will be required for an adequate power supply 10 years from now unless there is a commitment of regulators that these expenditures may be recovered from the customers.

As you are aware, there are many States which have adopted punitive attitudes to investors, which eventually will stop the flow of capital into the electric power industry. As I stated previously, my own company will not make the commitment to build new generating facilities without the assurance from our regulators that the cost of these plants will be recovered from customers.

Naturally, we must be able to demonstrate in advance that the powerplants are necessary and that the particular expansion plan represents the most economic alternative and that we have been prudent in the best interests of our customers, even though rate increases will be required to finance the new facilities. This, of course, may require changes in both Federal and State laws so that these assurances and commitments can be given.

Thank you very much, Mr. Chairman.

[The prepared statement of Mr. Turley follows:]

Statement of

Keith L. Turley

Chairman of the Board, and

Chief Executive Officer

Arizona Public Service Company

Before the

Committee on Energy and Natural Resources

United States Senate

July 23, 1985

Mr. Chairman and Members of the Committee, my name is Keith L. Turley. I am Chairman of the Board and Chief Executive Officer of Arizona Public Service Company (APS). APS is an investor-owned electric utility serving approximately 1.4 million Arizonans or abour 45% of the state's population in an area that includes all or part of 11 of Arizona's 15 counties.

As a sunbelt electric utility, we are being challenged as never before. In 1984 we experienced the greatest growth in our company's 100 year history as we added 30,900 new customers (a 6.6% increase) to our service area. Even as I speak, the demand for energy on our system is reaching all-time highs, already 8% greater than 1984. The fact that we are in a position to accommodate this growth and increased demand is more the result of perseverance, bulldogged persistence and commitment to a growing population rather than mutual cooperation and understanding between local regulators and the utility.

Fortunately, the utilities in the Western Systems Coordinating Council (WSCC), one of the nation's electric reliability councils composed of the 11 western states, and the desert Southwest have excess generating capacity at this time, because it was wiser to complete most of our current construction projects rather than abandon them when forecasted growth did not materialize. We are fortunate to have this excess capacity because the western part of the U.S., and particularly the desert Southwest, continue to grow.

The WSCC projects a growth rate of between 2.0 and 2.4% per year compounding over the next ten years, (21,300 Mw total), while the desert Southwest projects between 3.5 to 4.5% per year compounding over the next ten years (4,200 Mw total). The excess capacity assures availability to sustain growth into the mid 1990's when new sources of generation will be needed. Specifically, in the case of APS, we will complete the third unit of the Arizona Nuclear Power Project in 1987, marking the successful addition of approximately 4,000 megawatts of nuclear generating capacity to serve the utility customers in Arizona, New Mexico, West Texas and Southern California who are participants in the Palo Verde Project.

With its 1,100 Mw share of the project, APS will not require the addition of any new base load generating resources until 1995. However, with a 10-15 year lead time for planning, designing and constructing major facilities, we must begin the decision-making process now.

However, Mr. Chairman, the electric utility industry today faces a far more complex business environment than ever before. Actions of electric utilities, whether they be decisions involving new power plants, transmission siting, fuel selection or rate adjustments, have become major subjects of public debate and important considerations before regulatory bodies. Consumers are insisting not only on public accountability but also a greater role in the decision-making process. Some regulatory agencies are exercising 20/20 hindsight through the vehicle of prudency audits.

Historically, utility managements -- with the approval of their boards of directors -- have normally made all the decisions regarding future energy supplies and investment.

I am proud of my company's record. We have never failed the people of Arizona. We have always met our customers' energy needs with timely and efficient generating, transmission and distribution facilities.

However, faced with regulatory uncertainty and rate-making delays, as early as 1982 I took the position that I was no longer willing to recommend to my Board of Directors the launching of any new power projects unless the political, business, labor and consumer interests were in agreement with the need for a new energy supply for a growing Arizona. It is my experience that the construction periods for major facilities, which now extend from 10 to 15 years, are longer than the memories of respective authorities that regulate our industry, leaving hindsight as the measure of the quality of utility managements' decisions.

No longer am I willing to risk the savings of thousands and thousands of investors in the hope that politicians somehow will be supported in their rate decisions in face of the reality that no one likes higher rates.

So, what are our alternatives?

Recently after taking a new look at the long-term future, we adopted a new power-supply strategy designed to avoid the financing of any additional base-load generating facilities until after the turn of the century.

Our new power-supply strategy is now in place. Our plan is to look beyond conventional energy sources ... such as oil, gas, coal and nuclear ... and employ renewable sources of energy and other alternatives designed to minimize the need for us to raise new capital.

For example, we are already involved in solar technology. During 1984 we continued to produce energy from the 225-kilowatt Sky Harbor Airport Solar Photovoltaic facility.

And last year we met approximately 40 percent of the energy needs of an experimental solar-photovoltaic home located in Yuma, Arizona. We will continue our research and demonstration efforts to determine if solar-photovoltaic can be integrated into a utility system in a cost-effective manner.

We believe that the utilization of thermal storage, additional hydro-electric or pumped storage generation, the development of regional coal plants financed by others, and the upgrading of existing fossil plants, will avoid the need to finance any new power plants during the next 15 years.

Also, we will rely on increased load-and-energy-management by our customers as a substitute for building new generating facilities.

In addition, we will strengthen our transmission interties with other utilities in the West; explore investments in co-generation; and turn to the burning of solid waste.

Some examples: APS has taken a leadership role with other desert Southwest utilities in analyzing the economic and system benefits that may result from a major inland transmission intertie between utilities in the Pacific Northwest and the desert Southwest. The potential marriage of Northwest winter peaking utilities and the Southwest summer peaking systems should result in the sharing of the seasonal diversity, thereby eliminating the costs of new generating facilities of as much as 1,000 Mw on each end of the intertie. Since this intertie will go through three or four states and may have little or no local benefits, I am sure it will elicit considerable opposition. In order for the utilties to see this concept through to fruition will require the cooperation and support of the Departments of Interior and Energy plus acceptance in principle by local regulatory bodies and FERC.

On another front there is considerable interest in the West in third party construction and financing of power plants. This has been visualized as being accomplished through the establishment of joint ventures which would build and operate generating facilities financed on the basis of "pay-for-performance" contracts with various utility customers. There are three recent examples of this type of arrangement. Bechtel Power Corporation, General Electric Company, Combustion Engineering, Public Service Company of New Mexico, and the Navajo Nation have one project under discussion. The second involves Internorth, Gibbs and Hill and the Meeker, Colorado project. A third is under consideration by Sierra Pacific Resources. This project envisions a generating station financed and constructed by a consortium with the anticipation of making bulk power sales to utilities in the region. APS has been following the progress of these innovative concepts and will continue to weigh their potential.

One other thing we must constantly keep in mind is that many of our existing plants are 30-40 years old and must be modernized or replaced. Also, we must continue to de-emphasize oil and gas burners.

Underlying my comments today is the fact that the electric utility business is changing, and utility management and regulation must be progressive and flexible to accommodate and lead that change. Our customers and critics want to participate -- and we welcome them -- in an open decision-making process. Yet, many want the utilities to take all the risk as a tightly regulated, low rate of return industry. They also urge deregulation and competition between utilities. I'm not sure tight regulation and competition are compatible -- it's akin to playing poker with all cards face up.

In summary, there is need for additional power generating facilities for further growth which must be in the planning stages now. There are both traditional and new paths to follow. There are new risks, new technologies and new innovative financing schemes.

Even more important is the need for regulatory reform at both the state and federal levels. I do not know of any utility executive who would be willing to commit the enormous financial resources that will be required for an adequate power supply ten years from now unless there is a commitment from regulators that these expenditures will be recoverd from customers.

As you are aware, there are many states which have adopted punitive attitudes to investors which eventually will stop the flow of capital into the electric power industry. As I stated previously, my own company will not make the commitment to build new generating facilities without the assurance from our regulators that the cost of these plants will be recovered from customers. Naturally, we must be able to demonstrate in advance that the power plants are necessary and that the particular expansion plan represents the most economic alternative and that we have been prudent in the best interests of our customers -- even though rate increases will be required to finance the new facilities. This may require changes in both federal and state laws so that these assurances and commitments can be given in advance.

The CHAIRMAN [presiding]. Thank you very much, Mr. Turley. Senator Evans.

Senator EVANS. Thank you, Mr. Chairman.

This is a very interesting panel. Let me start with Mr. Smith. I think I have everybody's testimony here.

You talk about the planning environment the industry is now in on page 3 of your testimony, and the strategic implications of this are the tendency to build smaller scale relative to the past. And you go on to say, build only small capacity which better tracks demand growth and fluctuations, ignoring the economies of scale.

Isn't that what has gotten us into the big heap of the trouble we've gotten into over the past 10 years? We thought we could embark on huge new plants with an economy of scale and found out that the bigger it was the more it cost us per kilowatthour? Isn't that a lot of what has happened to us in the last 10 years? We thought we had economy of scale, and found out it was in many respects a forlorn hope.

Mr. SMITH. Senator Evans, answering your question based on my own personal experience which involves working with Carolina Power & Light Co. for the past 20 years, in that period of time we saw, and I think this is typical, the economies of scale turn in the late 1960's and early 1970's, which meant that every increment of new capacity that you added came in at a higher cost than previous capacity. What I was referring to——

Senator EVANS. I'm not talking about that capacity so much—I'm not talking about that. I'm talking about an individual plant, a 1,000-megawatt plant that ended up costing more than some smaller units. We just got far outside our bounds in terms of projected cost and ended up with cost per kilowatthour that turned out to be larger, not smaller.

Mr. SMITH. Well, my point that I sought to make was that the cost curve did turn for all kilowatts, regardless of whether they were kilowatts built into a small plant, let's say a 500-megawatt plant——

Senator EVANS. I understand that.

Mr. SMITH [continuing]. As compared to a 1,000-megawatt plant. And it wasn't the decision in any individual case to build a 1,000-megawatt plant rather than a 500-megawatt plant necessarily that changed the cost.

In other words, if you looked around the country, if you looked at the most recent large nuclear powerplant that came into service, which might be 1,100 megawatts, there would not have been any reduction in costs had you cut that down to 700 megawatts or 600 megawatts.

So I think you have to look at the specific projects where the large costs have occurred to find reasons for the costs. And the costs, I would submit, are not associated with scale as much as they are with the other elements in the environment.

Now I think that we will be building smaller plants because they are less expensive, fewer kilowatts, obviously fewer dollars invested, and I think we'll be able to site some of them on existing sites. I think that when we develop further the fluidized bed coal technology, that the indications are the economies of scale are roughly the same, whether you're talking about 200 to 300 megawatts or 600 megawatts. So I think you'll be doing some of that.

But I don't believe that one can accurately and fairly generalize with the statement that moving to large plants, using the economies of scale, was the reason for the high cost overruns, whether they would be cost overruns on our company's system or any other system.

Senator EVANS. Doesn't it make sense, given the uncertainty of forecasting, and the best we do in forecasting is still uncertain. All we have to do is look back over the last 10 years to see the unusual shocks that have occurred, and it's almost impossible to have anticipated all of those.

Doesn't that represent probably the biggest financial risk of all, the uncertainty of time, the risk of time, the length of time it takes to start and finish a project?

Mr. SMITH. The length of time certainly adds to the uncertainty because the longer the period of time the more events can change during that period of time. So that's a tremendously important element.

The uncertainty that we have faced in these long periods of time with regard to the nuclear plants has been specifically the changing nuclear regulations that we've had to contend with during the period of the late seventies and early eighties, double-digit rates of inflation, double-digit interest rates. And obviously, the longer the period of time the more these things are likely to occur.

Senator EVANS. Does that lead you to a planning horizon now that really does tilt largely toward shorter leadtime and smaller projects as a result?

Mr. SMITH. Yes; I think that's the pressure to build smaller projects with shorter leadtimes, even though over the life of the plant, let's say a 30- or 40-year timeframe, it may turn out that that was not the most economical way to serve the customer. But certainly that may be the safest way for the electric utility to proceed in the near term.

Senator EVANS. That's the balance we have to try to find, is the balance between cheapest and safest, which is always a tough one.

Mr. SMITH. Yes; over a period of time—exactly.

Senator EVANS. Mr. Kaslow, you mentioned in your testimony price-induced conservation as one of the elements that you were following. Do you have any explicit programs? Price-induced conservation is a reactive kind of thing. Do you have any explicit programs that tend to encourage better efficiency in the use of electricity? I would use pricing as one of those, explicit pricing that would maybe dampen peak demands. What are the kind of things you are doing?

Mr. KASLOW. We have a couple, Senator. We're filing in our largest rate jurisdiction currently, in fact have filed, a rate redesign that will move us toward fully allocated costs, and also a first step toward marginal cost pricing. This will probably end up being a three-step process, so we'll avoid the rate chart for certain customers.

Second, we are planning later this fall, this fall and into next year, two major demonstration programs, one in Massachusetts and one in Rhode Island, one focused principally on conservation incentives, and the second one focused on load management incentives.

These will involve customers in the thousands, and we hope this will give us some of the answers to what sorts of inducements does one have to propose to customers to get a response. That is a critical part of understanding just how far you can get with such a program.

Senator **Evans**. Isn't it, when it comes—it seems to me that we ought to approach the whole question of efficiencies, which I like to use better than conservation because I think it connotes more accurately what we're trying to get at, that every household, every commercial establishment, every industrial plant, and the owners of those various units have a valuable commodity, which is the electricity they use and which they may not have to use. And that valuable commodity is something that may be the cheapest way you can attain the new resources you need for load growth.

Doesn't it make sense to, instead of all this fussing around at the margins, to be more bold and go in? Why not offer an industrial plant $500, $700, $1,000 per installed kilowatt to share? Let them share with you the cost of building new and more efficient processes that may be of benefit to them but also give you electricity cheaper than you get anyplace else?

Have you gone that far in making those kinds of offers?

Mr. **Kaslow**. We are going down a route that's quite similar to that in our shared savings program, where we are working specifically and will be under this major demonstration with industrial and commercial customers, and essentially sharing the savings that will accrue through our or some other third party making the investment to provide the energy efficient services, if you will, or equipment.

I think that is an interesting approach and I think it's one that has some merit. However, we are also mindful of another constraint. That is that we do not want to be penalizing the balance of our customers through programs that may be specific or are really available to a limited number of our customers.

Senator **Evans**. But do you really if the reason for doing it is that that is the cheapest way to get the additional resources you need, doesn't that benefit all customers? Because if you had to go to the alternative more costly generation, that additional cost would reflect back on them?

Mr. **Kaslow**. If it turns out to lower the cost in the long run of all our customers, fine. We're just concerned about those where there can be some discrimination where certain customers are going to pay more to benefit those customers who are paying less, even though the result is reduced capacity needs.

But I think there are many things for us to learn as a company in that whole process, and that is why we are undertaking this major program.

Senator **Evans**. I see, Mr. Dahlberg, you wanted to comment?

Mr. **Dahlberg**. I wanted to add, part of that is the product of timing. That is, if you're in a situation now where you have a reserve of say 25 percent, if you offer an incentive to an industry to buy back the capacity presently you will end up with an expense that perhaps you cannot recover.

That is, if you are already under a lot of scrutiny for those kind of reserves, if you act now for the future, you still get penalized in the present period, and we've seen that happen in our system.

Senator EVANS. Mr. White, I was fascinated by the growth rates compared to the gross national product. Rather than however, matching the differential gross national product, it seemed to me it did quite the opposite. In that first period of time from 1960 to 1972, the electric load growth in your territory grew 65 percent faster than the GNP. In the next 10 years, it grew less than one-third as fast as GNP, and only in the last 2 years has it come back so it's about even.

Do you have any anticipation at all? What are your projections as you look forward? You have three wildly different circumstances there and the last one is only for a 2-year period which coincides with the period of economic recovery, which it seems to me probably jumps electric load growth faster than we would see over a longer period.

Mr. WHITE. I think you have to look at the character of our service area. We are in the industrial Midwest where we have a large industrial load. Close to 30 percent of our load is industrial, a lot of it in primary metals, aluminum, steel. During the period 1973 to 1982, these kinds of loads have suffered a great deal.

The aluminum industry particularly was in difficult trouble, and it appears that the aluminum industry even today is not healthy in this country. It did pick up again in 1982 through the 1984 period. So I think that during the period of 1973 and 1982, there was a decline in industrial activity, more in our area than in most regions of the country. And this impacted on our growth during that period.

On the other hand, when the growth did pick up in 1982 through 1984, we saw a sharper increase than perhaps the country as a whole. We are projecting for our peakload that it will increase at the rate of about 1.6 percent between now—annually between now and the year 1995.

Senator EVANS. That is based on what anticipation for GNP growth during that time?

Mr. WHITE. Well, the GNP growth that we're anticipating is something on the order of 3, 3.5 percent, Senator. That's one of the problems that we have. There's been a lot of discussion this morning about projecting the future. If we could get a pretty good hold on what the GNP growth is going to be over the next 10 years, if we could find economists that could do that for us, we would be able to project our peakloads very well.

Senator EVANS. Sure.

Mr. WHITE. We are projecting a greater increase in energy than that. We are projecting just under 2-percent growth per year in energy from now to the year 1995.

If I could, I would like to comment on the question you asked of Mr. Smith about the economies of scale.

Senator EVANS. Surely.

Mr. WHITE. We have built and have in operation today some five 1,300-megawatt coal-fired plants.

Senator EVANS. How large?

Mr. **White**. Five 1,300 megawatts. We have a sixth that's under construction now. There aren't any larger plants anywhere around, and we have found that on a dollar-per-kilowatt basis we will be willing to match anyone; and also in terms of the availability and the operation and efficiency of those units, they have been very good.

I think the problem——

Senator **Evans**. When were those built? What period of time?

Mr. **White**. The first one came into operation in 1979. The last one came into operation in 1984. We have one remaining unit that will come in operation that is scheduled for 1988.

But I think you have to look at a number of things when you determine the question of economies of scale: The size of the system, the growth rate, many things that you have to look at. I would agree that I think in periods of slow growth, we are going to be attempting to build somewhat smaller units, and we are looking at new ways of burning coal, as Mr. Smith pointed out, fluidized bed.

We are working in our company on pressurized fluidized bed. We believe that we can build smaller units and still capture some of the benefits of economies without losing the benefits of the economies of scale by building somewhat smaller. If they can be located in more locations than you can locate a large coal-fired unit, we think there will be major benefits.

But here again, if all goes well by 1990, we will put that unit into operation. It will take several years to get experience from it. We're talking about a demonstration plant of some 170 megawatts—some 70 megawatts. By the time we get to commercial scale, we will be in the latter 1990's. So we have to get from here to there.

Senator **Evans**. Thank you.

Mr. Chairman, I understand my time is up. I might just comment to Mr. Kaslow that—I'll probably get myself in big trouble doing it, but I've said it before—that I think on many cases the blind opposition to construction work in progress ends up costing customers more than they think they save under the circumstance.

I think I can make a pretty good case that the bulk of the trouble we ran into with the Washington Public Power Supply System was precisely because they were compounding their interest charges during a period of very high interest growth, and construction work in progress might have carried some of those projects through rather than killing them.

Mr. Chairman, I will have some other questions. I was particularly intrigued with Mr. Turley's concepts that his utility is carrying out now. I think they represent a pretty darn good view of the future and I'll have some questions I want to submit to him on that.

The **Chairman**. Thank you very much, Senator Evans. And there perhaps might be some time when I complete my questioning, if you'd like to ask some further questions.

Mr. Smith, on page 4 of your statement you refer to a 2-percent increase in growth rates. Do you mean 2-percent increase or 2 percentage points increase?

Mr. SMITH. I was looking for the line that had that reference, Senator. On page 2, a reference to a 2-percent rate of growth?

The CHAIRMAN. On page 4.

Mr. SMITH. Page 4. Yes, to a 2 percent difference in the rates of growth.

The CHAIRMAN. Two percent difference or 2 percentage points?

Mr. SMITH. Two percentage point difference. The word "point" should be there for clarity. It is the difference between 2 percent and 4 percent, which would be 100-percent difference——

The CHAIRMAN. A doubling of the growth rate.

Mr. SMITH. Yes.

The CHAIRMAN. All right.

Mr. White, on pages 3 and 4 of your statement, starting at the bottom of page 3 and continuing onto the top of page 4, you are talking about the growth rates you experienced, and you indicate that you expect about a 12.9 million-kilowatthour increase in demand. And by way of comparison, only slightly more than 7 million kilowatts of generating capacity is actually under construction.

Mr. WHITE. Yes, sir.

The CHAIRMAN. So you're planning or building less than you anticipate will be needed?

Mr. WHITE. Well, I'm speaking of the East Central Area Reliability Area, which we call ECAR, Senator.

The CHAIRMAN. Yes, sir.

Mr. WHITE. And the fact is that at this point in time ECAR has fairly high margins of reserves. So they're anticipating reducing——

The CHAIRMAN. You'll be able to absorb that by reducing the reserve?

Mr. WHITE. This is what they hope to do, yes, sir.

The CHAIRMAN. You also, at the end of the paragraph at the top of page 4, as you're talking about the future, you also point out that there are 105 million kilowatts expected to be in service in 1994, just 9 years from now, that would be at least 35-years-old by that time.

Mr. SMITH. 20 million kilowatts of the 105 million will be 35 years old or older.

The CHAIRMAN. Only 20 of the 105?

Mr. WHITE. Yes, sir.

The CHAIRMAN. The basic question I ask, the reason I go into that at all, is it looks like you are aiming for the low side of reliability.

Mr. WHITE. I think that in the East Central area of the United States we have had somewhat a lower growth rate in the past several years and, as many sections of the country, particularly the Southeast or the Northeast or even the Midwest, based on the base forecasts the companies in this area can make at this time, they do feel that the growth rate will be about two percent and that this will not take care of it.

But in actuality, after 1992, I believe it is, there is no further capacity scheduled to come into operation in these areas.

The CHAIRMAN. To return to the 2 percent growth rate, is it 2 percent after conservation?

Mr. WHITE. Yes, sir, overall.

The CHAIRMAN. So 2 percent real growth?

Mr. WHITE. Yes.

The CHAIRMAN. I am a little puzzled to know how, if indeed you expect that you are under that growth rate of 2 percent by 5.9 million kilowatts, with an obsolescence that attaches directly to 20 million kilowatts in the total of 105 during that period of time, no additions coming into the system after 1992, how much your reserve is going to carry you through the balance of the nineties.

I guess really the fundamental question I have is not one of criticism, but to try to find out why indeed you are aiming for the low growth. Mr. Turley has said very plainly why he has recommended to his board of directors that they build nothing. If I understand Mr. Turley's comments, and I think they are fairly easy to understand, he is not going to take the risk.

And I don't mean to belabor this, but I'm trying to find out what there is about your situation that leads you to aim for the lower end of the scale on growth rate, on new capacity, on replacement of old capacity, and then say there's no cause to worry.

Mr. WHITE. I think, sir, in terms of the capacity that is in place now, the intention is for most of the companies in the ECAR area and as for the American Electric Power System is to keep all the capacity we now have in operation continuing to operate. I believe by and large we can, although I have to say that capacity does not last forever. I think you can extend the life maybe from 35 to 40, 45, maybe even 50 years. But there comes a point beyond which I don't think you can continue to operate.

Actually, I have the figures for the ECAR area. Our projection is, as shown here, that we would have about 105 million kilowatts of capacity in operation in 1994. They are expecting a load of about 81 million kilowatts. So that would provide for a capacity margin of about 22 percent, which I think should be adequate.

Now, if the growth should be materially more than that, then we are going to have to get busy and start building plants pretty soon if we are going to meet that load growth. And I don't believe it is completely inconceivable that the growth could be greater than that.

We had a period, going back certainly to 1976–77, when the middle western part of the United States suffered a great deal economically. How long that will continue I guess is anyone's guess. But many of the people in that region are doing everything they can to try to pull it up out of the hole and get it growing again.

The CHAIRMAN. I guess if we continue to manufacture ever more automobiles in Japan we won't have to worry much about lack of capacity.

Mr. Dahlberg, on page 6 of your statement at the end of the next to the last paragraph on the page, you say: "While one may tend to minimize this statistic as weather-related, that is as a result of an extremely hot summer, you must recognize that we must have electricity available to meet the extreme situation, not just the average condition."

Why? Are you making the assumption that shortage is bad?

Mr. DAHLBERG. Yes, sir, I am.

The CHAIRMAN. Why is it bad? Why is it necessarily worse to have a shortage than it is to have an excess capacity which the consumers are asked to pay for?

Mr. DAHLBERG. The previous panel I think was asked almost the same question, and that is, are the costs, the social costs, higher for having too much capacity versus having too little. The studies we conducted on our system correspond with, I guess, the answers of that panel. That is, that we have found, giving some reasonable estimate of social costs—and I think Mr. Sherwood Smith gave you some of those in his testimony—that the costs of having overcapacity or so-called overcapacity are lower than having too little capacity.

The system also operates——

The CHAIRMAN. Hadn't—excuse me, go ahead.

Mr. DAHLBERG. The system also operates on the basis of meeting the load at all times. And it's like the guy, a 6-foot man, who drowns in an average 4 foot pond of water. That is, that we as a responsibility do try to meet load, not when we can but in every instance.

The CHAIRMAN. Mr. Dahlberg, you start out by the assumption, then, that you have an obligation to meet the demands of the system and now you're going to try to meet them. And you also stated, I believe, that the social costs of shortage are greater than the social costs of temporary excess capacity in order to have a sufficient capacity to meet peak demand.

Have you made an independent analysis of that, you or your company, in terms of the relative costs of the two alternative strategies?

Mr. DAHLBERG. Yes, we've looked at—I think I said social costs. We've really looked at total costs of over versus total costs of under, giving some value of the social costs of outages. We have done that for at least one of our subsidiaries, the largest. We could furnish that study for the record.[1]

The CHAIRMAN. I'd appreciate having it, if you would.

Mr. DAHLBERG. We'd be glad to do that.

The CHAIRMAN. Please.

Mr. Kaslow, you are in an area of the country which has a number of unique problems. Maybe they're unique. The debate over acid rain problems is both associated with the effects of acid rain and the public dialog and political discussions as a result of acid rain.

Looking to the future—and here I'm not talking about 50 years from now, but 15 to 20 years from now—is increased use of coal an option in the Northeast?

Mr. KASLOW. I think it is, Senator, and I don't think acid rain, the acid rain issue alone, would preclude building a coal-fired unit in New England. However, let me just say that the collection of environmental sensitivities in my view would make building a large central station unit, fossil-fired unit in New England now very, very difficult, very questionable.

I have hopes that over time that will change.

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[1] Not received.

The Chairman. Over how much time?

Mr. Kaslow. That's a good question. I think a lot of times people's reactions to issues are governed by the sense of urgency involved. And one has a perception that there's surplus capacity in a region, it may be comfortable to find all sorts of reasons why one shouldn't build anything. But as that surplus disappears and as there becomes the threat of a shortage in time, I think sometimes people's views of certain issues are tempered a bit.

The Chairman. Mr. Kaslow, in your statement you indicate that regional regulation would only add another layer of regulation and you don't want another layer of regulation. Would you consider the possibility of regional regulation as a replacement for State regulation in the instances where interties, wheeling, and generating companies are a factor?

Mr. Kaslow. Well, I—let me just give you my personal views. In all sorts of interstate actitivies, we have found that the FERC handling of these issues has generally resolved them, at least in our region of the country, without any great difficulty. So that mechanism exists, certainly on the transmission level.

In terms of other activities, such as siting or go/no go decisions on building powerplants, a lot of informal regional discussion takes place anyway through the State commissions and some of their staff people, and I think this also happens through other informal mechanisms.

I personally believe that if one tried to enforce a regional regulation structure in a region like New England, even if it were limited only to siting of powerplants, that it would be doomed to failure because the things that are important to southern New England may be quite different from the things that are important to northern New England. And I think within that six-State region there would always be differences where no State would be willing to give up their final veto, if you will, their final bit of authority. So for that reason, I think practically that it wouldn't work.

The Chairman. Mr. Turley, I notice your emphasis on the complementary nature of the northwest winter peaking and southwest summer peaking systems. Is there not a similar complementarity on a daily basis batween eastern and western utilities?

Mr. Turley. Yes, there is, Senator. I cannot quantify it, but there is an hourly difference between the time zones and the demand for power as it moves east to the west.

The Chairman. Have we adequately looked at the possibilities of trying to plug into that with interties?

Mr. Turley. I'm not sure we've looked at that adequately. I know it's been looked at and the intertie was made some years ago, a modest amount of power moving east and west. And I suspect it's something we ought to have another look at if it's not being looked at.

The Chairman. Mr. Smith, you stated that the heart of the problem of proving adequate new capacity is that political and economic incentives warrant avoiding investment altogether, regardless of the exact level and timing of the need for new capacity. I think that's a correct quotation of your statement.

Doesn't this suggest that serious shortages are inevitable in the 1990's unless the regulatory climate improves? Isn't the real question of when the shortages will occur and the answer simply depends on the rate of demand growth?

Mr. SMITH. Yes, I think that's exactly correct, unfortunately. And it would be our purpose to try to encourage Government and other interested parties to work with the utilities to see if it's not possible to remove those impediments toward building for an adequate supply.

The CHAIRMAN. Let me ask you all this question. It'll be my last question. I'll submit some for the record. Mr. Turley, you're perhaps more blunt than some of your colleagues, but I see an undercurrent in some of the other testimony that reflects some of what you've said. You said, I simply am not going to recommend any more until we get our act together, we as a country get our act together, we as a service area, all of the elements within it, decide we want it. Then we'll start building again.

That isn't quite so explicitly stated by others, but I get that undercurrent. Let me ask this question: Is that because there is no assured reward for building an adequate supply, whatever that might be? Or is it associated with the fact that there may be a penalty for overbuilding and no penalty for underbuilding?

What are the consequences to your company other than the PR problems you have if suddenly you have brownouts? Has any regulatory commission yet said that you've got to take that out of the shareholders?

Mr. Smith.

Mr. SMITH. Well, Senator, I think that unfortunately it's probably the question of both lack of reward, that is a lack of an adequate return on the capital that's put up by investors, plus the substantial risk of a penalty for some unforeseen occurrence that may happen in the future that was not anticipated by the utility or by the regulators when the project was started. I think it's a combination of both of those.

With respect to brownouts, there is a great deal of concern. We are individuals who work with regulated franchised utilities. We do have an obligation to seek to provide facilities for service. Yet we can only do that where the regulatory system permits us to know in advance of building a project what it is you'll be permitted to build, and then you can tell how long it will take to build it and you can estimate what it will cost.

And then you need to be able to tell the investors who will put money in the project what are the rules under which they will be allowed to earn a fair rate of return. Otherwise, they won't put money into the project.

We see a system, then, that says if you make judgments and the regulatory climate, the regulatory bodies, say your judgments were correct, you'll get a rate of return on that judgment and that investment. If their judgment is different than yours, there may be a substantial penalty.

If you fail to make the investment, what is the penalty? You know, it doesn't really strike me as being inconceivable that, if regulatory bodies are politically motivated or politically influenced, that they'll find the capacity to say, by a 20-20 hindsight application of the prudent man rule, whatever prudency may be, that you weren't prudent when you said: I'm not going to recommend any more plants; I'll take the chance of running shortages; and then we get down to the point where there are shortages, and then indeed there is a social cost calculation, and say: OK, we'll take that out of the shareholders.

The CHAIRMAN. Does that bother you, Mr. Turley?

Mr. TURLEY. Senator, it certainly does. And I for one will not let the lights go out. The penalty is, when we get to the point in time where it's clear that we're not going to be able to carry our load, we will be forced to build significantly more expensive plants, such as a combined cycle oil-burner.

You can do that in 2½ to 3 years, as opposed to 8 years for low cost coal or in our case 9 years for lower cost nuclear. So that the penalty is that the customers will pay more in the longer run if we don't bring some reason into how we do our planning.

The CHAIRMAN. Well, the regulatory body has been trying to find a way to take that penalty away from the consumers and put it on the shareholders, saying it's management's fault. You overbuilt; you swallow the load.

Can't they just as easily say: You underbuilt; you swallow the load? You could have built a nuclear power plant and given them cheaper power and you elected not to do it; that should come out of the rate of return on the shareholders.

Mr. TURLEY. Yes, sir, they could say anything. [Laughter.]

Mr. WHITE. Mr. Chairman, regulators are very inventive and they can find ways of punishing a utility, I think, if they don't feel that we have been sufficiently prudent in planning for the future, either with more or less.

But as Mr. Turley has pointed out, it will be with rather expensive alternatives. One of the points that has not come up this morning—there are no manufacturers here—but you know, as we run out of building plants and there are very few being planned today, the manufacturers' order books are vacant, whether it be for turbine generators or for boilers or whatnot, there are fewer piping manufacturers, there are fewer valve manufacturers around.

The people that built these things are retiring and they're not being replaced. If we get to a point where we have to add very rapidly to our generating capacity, we are all going to be up here trying to get priorities to get equipment ahead of the next fellow, and we'll go back to where we were. And I go back to Korea, when we had a plan here in Washington for rationing these materials to the various utilities.

The CHAIRMAN. Senator Evans took a chance a moment ago and made a comment he said might get him in trouble. That happens to be a comment I agree with, so maybe we're both in trouble.

I will hazard one further. That is, I am aware of the efforts that have been made to punish utility management and their shareholders by loading costs on them one way or the other and reducing the rate of return, forcing them to absorb losses. I think that is exactly the same effect as the adamant opposition to CWIP.

You can do that in the short run, but in the long run the consumers for that utility are going to pay that bill, because that means that that utility is not going to be able to get capital at low cost, is not going to be able to meet the needs of the consumers at the lowest possible cost. There will inevitably be higher cost electricity furnished to the consumers of that utility and in the long run the consumers are going to pay that bill.

They have been able to hurt that level of management during that short period of time. You may indeed be able to reduce the stock value of the utility for a short period of time. But ultimately the consumers in that area are going to pay a higher bill for their electricity.

This is a regulated business, and I hope we will try to do our best job of seeing that you do make good management decisions, and that they're overseen by regulatory bodies in the public interest, and that once those decisions are made, we'll forget the effort to try to pin blame on somebody and take a dollar out of their hide somewhere, because I see that affecting consumers ultimately.

Senator Evans, I don't ask you to endorse my statement, as I did yours, but I would make the same comment. I probably got myself in trouble by having made it.

But gentlemen, I am concerned. That's why we're having these hearings. I'm concerned about the adequacy of future service. You may have detected that in the questions I was asking, because I am not sure that just aiming for the lowest possible risk in terms of building plants and reducing reserves and the lowest possible growth rates is necessarily the way to eliminate risk.

You swap that for another set of risks. And as I suggest, the regulatory utility commissions, if indeed punitive actions is what they seek, may well find a way to punish that activity, too, and that may not be the lowest risk option you have.

I guess maybe why I sympathize with you, I don't know any way to avoid your fight save retire. [Laughter.]

Harry Truman used to say, accurately so: "If you can't stand the heat, get out of the kitchen." Maybe that's where you are, you and we too. Perhaps we can't avoid the public criticisms of our judgments, positive or negative.

I will have further questions to submit for the record.

Senator Evans.

Senator **Evans**. Mr. Chairman, I won't try to extend this past our time, except to say that I wholeheartedly endorse the statement partially. [Laughter.]

That leads me to my final question, which is really addressed to Mr. Turley. I was really struck by the forcefulness and I think the excellent management that you are producing for your company and the kind of planning that you have adopted.

Wouldn't you say that, even if you didn't have the current problem with embarking on any new central plant facilities, that the base or the power supply strategy you set forth here would for the most part, maybe all, still be a pretty good strategy?

Mr. **Turley**. Yes, sir, I believe it is. Our responsibility is to supply energy at the lowest possible cost, and I think this strategy will do that, or it should not be any greater than moving ahead with big new baseload plants.

One of the strategies which you asked one of the questions earlier of one of the members of the panel was, what are you doing with customers? Well, we have a rate for our residential customers, a demand energy rate, just as though they were a commercial or industrial customer. There's an incentive for them to diversify the demand they put upon our system.

And so we are selling them load controllers at zero interest rate so that they can make sure, Mr. Chairman, that the hot water heater isn't running at the same time the heat pump is in the winter or even in the summer time. And they can save significant sums of money in those kinds of fashions.

We are buying, as it were, capacity from our customers. There are a lot of old, inefficient refrigeration units out there in that marvelous desert, and we are paying our customers upwards of $50 a kilowatt to throw away the old and buy the new, and they will have less demand as a result on our system, so we don't have to build a new powerplant to the degree we can buy capacity back.

We're doing a number of things like that and I think we'll make it work.

Senator EVANS. It just seems to me that it makes all the sense in the world, especially if those things—they may be a little more difficult than one single construction project, since you have to deal with thousands of customers. But if the end result is cheaper and it gets you there without the administrative and regulatory hangups that we seem to run into with our central powerplants, that it seems to me is the cheapest, lowest risk option, which is what everybody ought to be seeking.

Mr. TURLEY. It is cheaper to build a transmission line to the northwest, Senator, than it is to a new powerplant.

Senator EVANS. Right now we've got lots of power and we would like to sell it to you at an appropriate price, of course.

Mr. TURLEY. I'm willing to negotiate right now.

Senator EVANS. Just one final thing, because it does deal with the question the chairman asked. When you stated at the end, "My own company will not make a commitment to build new generating facilities without the assurance from regulators that the cost of these plants will be recovered from customers," that's a pretty straightforward statement.

Is there a point, however—what do we run into on what I believe are the rare circumstances where someone simply may just mismanage and you end up with a heck of a lot higher price than any? You know, I know all of the hindsighting that's going on, far too much of it. But there are those rare cases where that happens.

Would you still believe that all of that excess cost must be borne by the customer?

Mr. TURLEY. No, sir. But Senator, if you mismanage you ought to pay the piper in my judgment.

Senator EVANS. What we have to do is try to get the public utility regulators to the point where they understand the difference between the rare case that may happen and the much more frequent case where, with the best of predictions and the best of intentions, you intend to build for the future and looking backward you see you didn't need it. There's an appropriate——

Mr. SMITH. Senator, may I add one small footnote to Mr. Turley's answer with which our industry agrees? That if the company is actually imprudent, or negligent, or mismanages, then obviously the ratepayers shouldn't pay the cost of that. The issue is, when is the utility expected to make the judgment? And the most important thing for the utility in assuming some responsibility for prudent management is to know that his decision will be judged in the light of the circumstances available to him at the time the decision was made and not made in the light of circumstances that will evolve over the next 5 to 10 years.

Senator EVANS. I agree.

The CHAIRMAN. Thank you very much. I appreciate your testimony.

I had earlier announced we would recess until the hour of 2. I will now change that until 2:15 p.m., when we will come back. Thank you, gentlemen, very much.

[Whereupon, at 1:10 p.m., the committee recessed, to reconvene at 2:15 p.m. the same day.]

AFTERNOON SESSION

The CHAIRMAN. The hearing will come to order.

Our third panel today is Mr. Floyd W. Lewis and Mr. Edward A. Brown. Gentlemen, if you'd take your seats at the table, we will start out by hearing your testimony.

STATEMENT OF FLOYD W. LEWIS, CHAIRMAN OF THE BOARD AND PRESIDENT, MIDDLE SOUTH UTILITIES, INC.

Mr. LEWIS. Thank you very much. Mr. Chairman, members of the committee:

I would agree with the general theme expressed by this morning's panel of industry witnesses, that the greatest impediment to meeting the future demand for electricity is the regulatory climate which threatens to penalize utilities who build plants to meet anticipated loads. Our Grand Gulf Nuclear Station experience is a prime example of this behavior.

Middle South Utilities is a registered public utility holding company, with four subsidiary electric companies operating in parts of four States. The generating and transmission facilities of the Middle South system have been planned and constructed on a coordinated basis and are operated on a fully integrated basis, meeting the standards of the Public Utility Holding Company Act of 1935.

In the early 1970's, decisions were made to build Grand Gulf Nuclear Station both to meet future load growth and to diversify our fuel supply away from overdependence on oil and gas. No one of our operating companies had the financial capability to construct both Grand Gulf units, and that was also true of the operating companies as a group.

In 1974, Middle South Energy was formed to finance Grand Gulf for the system. Part of the necessary financial backing for Middle South Energy were agreements entered into in 1974 between Middle South Energy and the operating companies. Both the formation of Middle South Energy and the agreements with the operating companies required the approval of the Securities and Exchange Commission. Under procedures which provide public notice and opportunity for hearings, the SEC approved both of these. No State public utility commission raised any objections.

In about 1980, when we thought that Grand Gulf Unit One would become operational in 1982, all four operating companies considered Grand Gulf highly desirable as an economical source of energy. So the operating companies decided among themselves that Grand Gulf would be allocated with Arkansas Power & Light Co. taking none or zero, since it already had two nuclear units as well as four coal units under—pardon me, under construction. Because financing had been secured based on the underlying agreements, Arkansas Power & Light was still potentially liable for a portion of the costs of Grand Gulf.

Now, some have charged that we set up Middle South Energy to avoid regulation. However, we've just gone through two Federal Energy Regulatory Commission cases with 22 parties in one and 29 parties in the other. The two FERC proceedings included 63 days of hearings, more than 9,900 pages of transcript, and over 640 exhibits.

In these cases, five State and local regulatory agencies participated fully, with each arguing for a lower share of Grand Gulf at the expense of the other jurisdictions. The FERC in its decision on June 13, 1985, allocated 36 percent of Middle South Energy's Grand Gulf costs to Arkansas Power & Light Co., 33 percent to Mississippi Power & Light, 14 percent to Louisiana Power & Light, and 17 percent to New Orleans Public Service.

All of the State and local regulatory authorities are resisting flowing the FERC-approved costs through to their ratepayers, even though the plant is now commercially generating electricity. It went commercial on July 1, 1985.

An independent audit commissioned by the Mississippi Public Service Commission to look into the construction and the costs and time on Grand Gulf found that none of the cost increases were due to mismanagement on our part. A copy of the executive summary of that audit is included as attachment 3 to my written statement.

Senator Bumpers has introduced a bill, S. 1149, that would in effect let the State public utility commissions reverse the FERC in the Grand Gulf case. Attachment 4 to my statement is a legal opinion on why S. 1149 as drafted is unconstitutional.

I believe it would also be unwise and very unfair. Not only was the Arkansas commission's approval not required for the construction of Grand Gulf; there was no statutory authorization for the Arkansas commission to grant a certificate or approval for the construction of a powerplant located outside of the State.

It's been claimed that FERC is ordering one of our companies to buy power it doesn't need. The FERC said in their order that the issue here is not whether a company should be forced to purchase or sell power, but rather what is the appropriate allocation of costs among integrated companies owned by the same parent.

Other critics claim that our ratepayers should not pay for what they claim is excess capacity. Only someone who completely ignored the national energy policies over the last decade could accuse us of having excess capacity. Grand Gulf was built both to meet future load growth and to diversify our fuel supply, and it will do both.

Without Grand Gulf Unit 1, our capacity margin would fall below an acceptable level by 1991. It's completely unreasonable to contend that at any given point in time generation resources must precisely match loads and reserve obligations.

We face the ultimate paradox of having built coal and nuclear capacity to reduce our dependence on foreign oil and then having our success thrown in our face by critics who point to the resultant falling price of oil and proclaim our actions as imprudent and unnecessary.

I'm confident our actions will stand up to close scrutiny before any impartial body. It appears very likely, however, that we will have to pursue our rights in the courts. Unfortunately, this takes time, and the financial consequences of such delays can be very substantial for the companies and their customers.

[The prepared statement of Mr. Lewis follows:]

STATEMENT
BY
FLOYD W. LEWIS
CHAIRMAN OF THE BOARD AND PRESIDENT
MIDDLE SOUTH UTILITIES, INC.
BEFORE THE
COMMITTEE ON ENERGY AND NATURAL RESOURCES
OF THE
UNITED STATES SENATE
JULY 23, 1985

I am Floyd W. Lewis, Chairman of the Board and President of Middle South Utilities, Inc. I appreciate having the opportunity of testifying before the Committee on Energy and Natural Resources. This Committee has scheduled this hearing to examine the general question "When Will The Lights Go Out?". However, I have been requested to focus my remarks more specifically on issues regarding the Grand Gulf Nuclear Station and the recent Federal Energy Regulatory Commission's decision regarding the allocation of the costs of Grand Gulf Unit 1 among the Middle South operating companies.

GENERAL

Middle South Utilities, Inc. (MSU) is a holding company registered under the Public Utility Holding Company Act of 1935 and neither owns nor operates any physical properties. MSU owns all of the outstanding common stock of four operating electric utility subsidiaries, Arkansas Power & Light Company (AP&L), Louisiana Power & Light Company (LP&L), Mississippi Power & Light Company

(MP&L) and New Orleans Public Service Inc. (NOPSI), and of Middle South Energy, Inc. (MSE), a generating company formed in 1974, which has been constructing and financing its 90 percent ownership interest in the Grand Gulf Station. The work of designing, constructing, operating and maintaining Grand Gulf Station is being performed by Mississippi Power & Light Company under contract as agent for MSE.

The term "Middle South System" is generally used to refer to MSU and its various direct and indirect subsidiaries. The electric generation and transmission facilities of the Middle South System are planned and constructed on a coordinated basis and are operated on a fully integrated basis from a dispatching facility located in Pine Bluff, Arkansas.

BACKGROUND

Prior to the 1970's, substantially all of the Middle South System's generating facilities were built to burn natural gas as the primary fuel. As it became more difficult to secure long term natural gas contracts, it was recognized in the late 1960's that the companies needed to diversify their fuel base.

In 1967 a decision was made to construct a nuclear generating unit in Arkansas, the first such unit in the Southwest part of the country. In 1970 a decision was made to build a second nuclear unit in Arkansas and to construct the first nuclear unit in Louisiana, Waterford 3.

During the late 1960's and early 1970's the peak system demand was growing at approximately 10 percent per year and was forecast to grow at about 9 percent per year through the decade of the 1970's and into the 1980's. Lead times for nuclear plants were considered to be approximately six to eight years.

Studies in this time frame showed that nuclear power plants would produce electricity at considerably lower costs than fossil fuels, including coal.

Based on these load forecasts and cost studies, two more nuclear units were planned. One was to be located at the current Grand Gulf site which is just outside Port Gibson, Mississippi and would be owned by MP&L and scheduled for commercial operation in 1979. The other would be located in South Louisiana, owned by NOPSI, and scheduled for commercial operation in 1980. Both of these units were to be 1250 megawatt units.

In 1972 further studies showed that construction costs would run approximately 25 percent higher for the South Louisiana site than the Grand Gulf site primarily because of poor soil conditions. Because of these cost considerations, a decision was made to locate both units at the Grand Gulf site, with the first unit to be in operation for the peak season of 1980.

These decisions to construct nuclear units were reinforced by subsequent developments. Through the 1970's, the supply of natural gas for electric generation became increasingly scarce and deliveries of gas to the operating companies were curtailed by their suppliers. In January, 1973, the Federal Power Commission promulgated guidelines for curtailment of natural gas service by interstate natural gas pipelines which accorded the lowest priority to gas used for generation of electricity.

Also, during the 1970's the actions of Congress and the Executive Branch of Government greatly impacted our planning and decision making process. Using the Congressional Quarterly Almanac, we have summarized, by years, major federal legislative and executive actions directed at electric utilities with respect to their continued use of oil and natural gas as boiler fuel. This information is appended as Attachment 1. Laced throughout the various Congressional and Executive Branch proposals for solving the energy crisis was the common thread that utilities must stop using oil and gas as boiler fuel.

Historically, the construction and financing of all new generation have been the responsibility of each operating company. Units were sited on the basis of need to meet peak demand, optimal location of the new capacity and ability to finance. Generation expansion plans are coordinated by the Middle South Operating Committee, comprised of representatives of each of the operating companies and MSU.

Because of the sizes and projected capital costs of new nuclear units, it was realized that the smaller operating companies such as MP&L and NOPSI would have a difficult, if not impossible, time financing these units. This could leave them in the untenable position of having to rely on gas and oil for all future needs. As a result of studies undertaken to resolve this problem, it was determined that ownership of the Grand Gulf project by a new MSU subsidiary was the most desirable alternative.

FORMATION OF MSE

MSE was formed on February 11, 1974 as a wholly-owned subsidiary of MSU and activated in the middle of that year following receipt of the Securities and Exchange Commission's approval under the Public Utility Holding Company Act of 1935. At that time, the express purpose of MSE was to construct, finance, own and operate certain future base load generating facilities for the Middle

South System. In particular, MSE was created as a means of handling the financing of the Grand Gulf project, then in its initial stage of construction near Port Gibson, Mississippi and owned by MP&L.

As indicated above, the cost of the two 1250 megawatt Grand Gulf nuclear units was too great for MP&L alone to finance. Cost estimates at that time indicated that the first unit alone would cost approximately one and a half times the amount of MP&L's 1973 year-end net plant account. In fact, it would have been impossible, considering the size of the individual System operating companies and the other construction activities within the MSU System, for any of the System operating companies individually to finance a project of this magnitude in the time frame of the proposed construction schedule. It was determined that ownership of the project by a new MSU subsidiary - i.e., MSE - was the most desirable alternative. Effectively, the new subsidiary would have the full financial backing of the entire Middle South System. In June 1974, MSE, with the approval of the Mississippi Public Service Commission, purchased the Grand Gulf Station from MP&L at a cost equal to the original book value totaling approximately $20 million and in addition, contracted with MP&L, as agent, to design, construct and operate the Grand Gulf project, on MSE's behalf. MSE's only activity to date has been limited to the Grand Gulf project.

An application for the requisite nuclear construction permit was filed by MP&L with the Atomic Energy Commission in November 1972, and was later joined by MSE. MSE and MP&L, after a public hearing, received a certificate of public convenience and necessity from the Mississippi Public Service Commission in May 1974. On September 4, 1974, the Atomic Energy Commission issued construction permits for both Grand Gulf units and full scale construction was begun in late September of 1974. At that time, the construction schedule called for 64 months to commercial operation of Unit 1 at an estimated cost of $880 million.

MSE entered into a series of agreements with MSU and the System operating companies which have been used to provide the credit support necessary for MSE to enter the capital markets. MSU and MSE entered into a Capital Funds Agreement whereby MSU agreed to supply sufficient capital for MSE to (1) complete and operate the Grand Gulf project, (2) maintain an equity capitalization ratio of 35 percent and (3) repay, at maturity, notes under the U.S. Bank Loan Agreement, MSE's principal source of debt capital to finance the Grand Gulf project.

To provide additional credit support for MSE, the operating companies and MSE, in 1974, entered into the Availability Agreement, whereby MSE agreed (1) to make available to the System operating companies all power available from its share of the Grand Gulf Station and (2) to enter into a System Agreement with the System operating companies prior to commercial operation of Grand Gulf Unit 1. The System Agreement among the operating companies provides for, among other things, the basis for allocation of power among all the Companies and for the terms of payment for this power. In return, the System operating companies agreed to pay MSE monthly for the right to receive power available at the Grand Gulf Station and such amounts, when added to amounts received from other sources, would be at least equal to MSE's total operating expenses and interest charges with respect to the Grand Gulf Station.

The Availability Agreement, as amended in 1981, provided that the sale of power may be governed by a separate power purchase agreement (Unit Power

Purchase Agreement) rather than the System Agreement and also fixed the allocation percentages as follows: AP&L - 17.1 percent, LP&L - 26.9 percent, MP&L - 31.3 percent and NOPSI - 24.7 percent. These allocations were amended later in 1981 under a Reallocation Agreement whereby AP&L relinquished its rights, benefits and interest in the project and LP&L, MP&L and NOPSI assumed all the obligations of AP&L with respect to its responsibilities under the Availability Agreement. AP&L was, however, still to be obligated to make its share of the payments if the other operating companies were unable to meet their contractual obligations in this respect.

The System operating companies also entered into a Power Purchase Advance Payment Agreement with MSE whereby, in accordance with the percentages specified in the Reallocation Agreement, if Grand Gulf Unit 1 were not placed in commercial operation by December 31, 1983, such companies would make advance payments to MSE for power purchases in the aggregate of $12.5 million per month. Such payments would continue until December 31, 1984, later extended to December 31, 1985, or commercial operation of Unit 1, whichever occurred earlier. Repayment of power purchase advance payments made to MSE will be subordinated to the payment in full of all loans under the U.S. Bank Loan Agreement, including interest thereon. However, after commercial operation, MSE will be permitted to credit accumulated power purchase advance payments over an 18-month period to the appropriate System operating companies, including interest, against their respective obligations to pay for capacity and energy from Grand Gulf. As a result of the above arrangements, MSE had the financial strength to complete Grand Gulf Unit 1. With this structure, MSE was able to raise much larger amounts of capital than any one System company could have done.

MSE's future activities will be determined to a large extent, by the treatment of the recent FERC decision on the Unit Power Sales Agreement and the System Agreement proceedings by the various state and local regulatory bodies. Resolution of the federal preemption issue will be paramount in determining the viability of MSE as a vehicle for pursuing the System's future generation expansion plans.

ALLOCATION OF GRAND GULF

As stated above, the original Availability Agreement, as filed with the Securities and Exchange Commission (SEC) in 1974 (File No. 70-5399) anticipated that, on or prior to commercial operation of Grand Gulf Unit 1, MSE would become a party to the then existing 1973 System Agreement. Under that System Agreement, MSE would have had no load responsibility and, hence, all of MSE's Grand Gulf capacity and energy would have been purchased by the operating companies in proportion to their relative deficiencies in capability (each company's proportionate share of System capability less actual company capability). These company allocations would have changed frequently as the operating companies' load responsibilities changed due to different weather conditions and growth rates and as capabilities changed because of the addition and retirement of generating units and changes in the amounts of purchases from non-affiliated entities. It subsequently became apparent that the "floating" allocation of Grand Gulf capacity under the 1973 System Agreement would have resulted in frequent rate proceedings, involving both rate increases and decreases.

Furthermore, other factors also led to reconsideration of the original allocation methodology.

Because nuclear and coal generating units have a higher capital cost, but lower fuel costs than oil or gas generation, their costs to produce energy are highest in the early years of operation, before they are appreciably depreciated, and lower in the later years. Also, the fuel costs for nuclear power are much less than fossil fuels and are expected to increase at a much lower rate in the future. For these reasons, it was decided to allocate permanently the capacity from Grand Gulf among the operating companies so that the company which paid for the capacity in the early years, when it was more expensive, would have this same capacity in the later years, when it was less expensive.

Subsequent to the 1973 Arab Oil Embargo, the cost of natural gas and oil was escalating rapidly. The future availability of these fuels in adequate, assured amounts was a matter of serious national concern. The Power Plant and Industrial Fuel Use Act of 1978 prohibited the use of natural gas as a primary energy source in any existing electric power plant after January 1, 1990* and prohibited immediately the construction of any new power plants which burned either oil or natural gas. This further reinforced the decision to construct base generating units fueled with nuclear and coal as rapidly as the units could be financed.

*This provision was not repealed until 1981.

Thus, it was determined that each operating company should move towards having, through purchase or installation, its proportionate share of nuclear and coal-fueled base generating capacity. If MSE had become a party to the 1973 System Agreement it would have taken what was considered an unreasonable time for "long" companies (those companies whose generating capability exceeds their proportionate shares of total System capability) to participate in Grand Gulf's low fuel cost nuclear energy. These "long" companies would have been precluded from having the nuclear base generation that they would need to minimize fuel cost and to diversify their fuel base. This problem was made more acute because of the slow-down in load growth and the tremendous rises in oil and gas prices following the 1973 Arab Oil Embargo. If the companies "long" on gas and oil-fueled generation were to have timely access to nuclear base generation, thus minimizing their fuel cost, it was necessary to allocate Grand Gulf on a fixed basis. Further, the price of oil again skyrocketed in the fall of 1979, as a result of the turmoil in Iran. This event emphasized the desirability of completing the Grand Gulf project notwithstanding the repercussions resulting from the TMI incident.

The Chief Executive Officers of the Middle South System companies, in January, 1980, agreed to a fixed allocation of Grand Gulf, which was embodied in the 1981 Reallocation Agreement. Over several years prior to that agreement, many studies were performed based upon various actual and forecasted conditions, various assumptions and various allocation and equalization methods. These studies considered a number of alternatives which, respectively, resulted in certain advantages and disadvantages for the operating companies. The common thread which ran through all of these studies was the overall objective to achieve a fair and equitable allocation of the Grand Gulf capacity and energy among the Middle South operating companies. As would be expected, the results of the various studies were the subject of extensive discussion among the companies and the final allocation was arrived at by negotiation, with each company keeping its common and separate interests in mind. The final allocation was the result of a review begun in late 1979 based on the following goals:

1. To move each operating company toward having its proportionate share of coal and nuclear base generating units.
2. To assure the benefits of base generation's lower and more stable fuel prices to operating companies not otherwise having adequate base generation.
3. To reduce the difference in the fuel price of energy among the operating companies.

The final proposed allocation was incorporated into a Unit Power Sales Agreement executed on June 10, 1982 and filed with the FERC on June 18, 1982 in FERC Docket No. ER82-616-000.

FERC LITIGATION HISTORY

The genesis of what came to be known as "the Grand Gulf Case" was the proposal to sell all of the capacity and energy (power) available to MSE from Grand Gulf to LP&L, MP&L and NOPSI pursuant to the June 10, 1982 Unit Power Sales Agreement (UPSA). The UPSA provided that each purchaser would pay its proportionate share of the total cost of power from each unit, as defined in that agreement. The shares of power available to MSE from Grand Gulf under the UPSA which would have been purchased by LP&L, MP&L and NOPSI, respectively, are as shown in Attachment 2.

By Order issued August 25, 1982, the Commission accepted MSE's UPSA and related Billing Format for filing, found that the filing constituted a rate change rather than an initial rate filing and suspended the rates to become effective, subject to refund, upon the initiation of service from Grand Gulf.

The start of the other FERC case (the "System Agreement Case") was the filing with the FERC of a revised System Agreement on April 30, 1982 in Docket No. ER82-483-000. The System Agreement sets forth the terms and conditions for transactions among the four MSU operating companies. Transactions among the companies have been governed by some form of system agreement for over 30 years. The system agreements have provided the contractual basis for the coordinated planning and operation of the companies' generating units and also have provided a basis for equalizing certain cost imbalances that result from this method of planning and operating the units.

The two cases proceeded contemporaneously. The hearing in the Grand Gulf Case lasted 18 days and fills some 2,900 pages of testimony. The hearing in the System Agreement Case went on for 45 days, and its transcript is more than 7,000 pages long. The two cases together involved the filing of more than 640 exhibits. There were 22 parties in the Grand Gulf Case and 29 parties in the System Agreement Case.

The major objection of many of the intervenors in the Grand Gulf Case concerns the decision to sell all of MSE's Grand Gulf output only to LP&L, MP&L and NOPSI, and none to AP&L. Presiding Judge Liebman concluded (in February 1984) that, based on the evidence that the Middle South System is a single integrated and coordinated electric system operating in Louisiana, Mississippi, Arkansas and Missouri, the costs of Grand Gulf capacity and energy should be shared equitably by all four operating companies and their customers. After finding the proposed entitlement percentages unjust, unreasonable, and unduly discriminatory, the judge adopted the allocation proposal of the Louisiana Public Service Commission (LPSC) and Occidental Chemical Corporation (OCC) for Grand Gulf Unit 1. Judge Liebman's recommended allocation is shown on Attachment 2. The effect of the judge's decision was not just to allocate Grand Gulf costs, but to allocate the cost of all nuclear capacity on the MSU system. The positions of the intervenors in the System Agreement Case ranged from complete equalization of all System production costs to acceptance of the agreement as filed.

Presiding Judge Head, in February 1985, set forth his recommended Grand Gulf allocation plan which, based on 1984 energy demands, would have resulted in the allocation shown on Attachment 2. He also recommended approval of the System Agreement as filed with only minor changes.

A January 1985 filing (prior to Judge Head's decision) of a Proposed Offer of Settlement by MSU subsidiaries to settle the allocation issue called for stockholders to absorb about one-third of the costs of Grand Gulf Unit 1 through December 31, 1990. Had the state regulatory and other parties accepted that offer, customers of the operating companies would have been charged initially for only 67.1 percent of the unit as follows: AP&L, 17.1 percent; LP&L, 14 percent; MP&L, 19 percent; and NOPSI, 17 percent. The stockholders' participation in cost sharing under this proposal would have ended effective January 1, 1991; and the operating companies would then have assumed additional allocations of: AP&L, 10.8 percent; LP&L, 13.5 percent; MP&L, 5.4 percent; and NOPSI, 3.2 percent.

MSE and the operating companies participated actively in a settlement conference convened by the FERC and attended by all the parties in March of this year. In announcing that settlement conference, FERC Chief Administrative Law Judge Curtis L. Wagner, Jr., said "There is absolutely no question concerning the fact that a negotiated settlement of these very complex and difficult proceedings will be in the public interest." A number of alternative settlements were offered and discussed during the course of the conference, but the principal issues remained unresolved after two days, and the conference was ended by Judge Wagner without a settlement.

On June 13, 1985, the FERC issued its Opinion and Order concerning both cases. The Commission affirmed Judge Head's findings rejecting the various allocation proposals in the System Agreement case and approving the System Agreement as filed, with only minor changes. The Commission then rejected Judge Head's Grand Gulf allocation in favor of Judge Liebman's decision, giving AP&L a 36 percent allocation, LP&L a 14 percent allocation, MP&L a 33 percent allocation and NOPSI a 17 percent allocation.

Subsequent to the FERC decision, the Middle South Utilities System again offered to allocate certain costs from Grand Gulf to the Middle South Utilities, Inc. stockholders. This would have had the effect of reducing the percentage allocations of each company until 1995. As a part of this offer, the issue of prudency would be resolved by the FERC and the allocated costs of Grand Gulf Unit 1 would be promptly reflected in retail rates. None of the regulatory bodies accepted this offer.

JURISDICTION

The reason for the institution of federal authority over utility transactions was the existence of an area of the utility business which was beyond the scope of state regulatory authority. In this sense, federal regulation is supplemental. Thus, in determining whether or not any matter should be reviewed by federal or state authorities, it is proper to study whether or not issues concerning the particular project under review can be resolved at the state level. The Grand Gulf proceedings give us an excellent example of a project which cannot be regulated at the state level without fragmentation and the resulting disregard of the advantages of interstate operation. If each state in a multistate project is given an effective veto over a project of this scope, which it is free to exercise in pursuit of its own parochial interests, interstate commerce would be severely constrained. It could not have been the intent of Congress, in recognizing the states' regulatory roles, to give a blanket authorization to state actions which are serious barriers to interstate commerce. On the contrary, by encouraging pooling and other such cooperative efforts, Congress has recognized the benefits of such commerce. Turning ultimate regulatory authority over such projects to protectionist state commissions would fly in the face of the Commerce Clause of the U.S. Constitution and result in a fragmented and less efficient electrical system to the detriment of the country. Regulation of a multistate project can only be carried out impartially and in the national interest by a regulatory body which can examine all facets of such a project. Only exclusive review by a federal agency such as the FERC is appropriate where many states are involved.

CONSTRUCTION PRUDENCY

Since the cost and schedule for constructing Grand Gulf has changed significantly since the inception of the project, the Mississippi Public Service Commission initiated a construction audit of the project in late 1984. In April, 1985 the Commission's consultants issued their report, which included the following major conclusions:

- "In general, all significant cost and schedule increases on Grand Gulf were due to factors associated with the growth of the nuclear power industry during the 1970's and early 1980's and not to factors unique to the project itself."
- "Factors causing major cost escalation and schedule slippage were industry-wide in nature and beyond the direct control of MP&L."
- "Review of the project indicates that MP&L took measures to minimize the cost and schedule effects of industry-wide events and other impacting factors."
- "While a number of project activities were performed by others, MP&L adequately planned, participated in and managed these activities, and met the evolving needs and demands of Grand Gulf."

In comparing the schedule of Grand Gulf Unit 1 with recent industry data, the consultants found that:

- "For units which began in the same time frame as Unit 1, the total project duration (NSSS award to commercial operation) of Unit 1:
  - is five percent less than the industry average for all units
  - is two percent less than the industry average for BWR units"
- "For units which were or will be completed within the same time frame as GGNS Unit 1, the total project duration of Unit 1:
  - is seven percent less than the industry average for all units
  - is 11 percent less than the industry average for BWR units"

Additional details are included in the Executive Summary of the Grand Gulf Construction Audit, a copy of which is appended as Attachment 3.

PRUDENCE OF PAST DECISIONS

"Prudence" is a term we have heard in a number of forums recently. The meaning of the term varies with the speaker. Some would contend that the only prudent decision is a decision which is judged to be best by all parties viewing it from hindsight. Such equating of prudence with clairvoyance not only offends basic notions of fairness, but creates untoward practical difficulties in the area of financing large projects. The current harassment of virtually every utility with significant construction work bears witness to this. Certainly no regulatory body on earth could function if this standard were to be applied to its own decisions. In addition, such regulation from hindsight is constitutionally infirm in that it impairs freedom of contract and creates new legal duties attaching to past events. (See Attachment 1).

Prudence, in a regulatory framework, should not mean perfection in the eyes of a particular regulator. A more fitting standard would be the one now employed by the FERC and other enlightened regulators: "Was the decision, in light of all factors known or properly knowable at the time the decision was made, a reasonable decision?". Regulation should seek to root out self-seeking abuses of power, not to second guess well thought-out-decisions made with the best interest of utility customers and shareholders at heart.

We believe the Grand Gulf project can be shown to be prudent under any reasonable standard. Fulfillment of our legal duty to serve in the changing world created by international cartels, uncertain fuel supplies, and new governmental restraints was a primary factor in determining to launch upon a program of fuel diversification which included Grand Gulf. Gaining the long term benefits of price stability in this climate was certainly prudent. Long term security for the purchasers of our power cannot be gained through a series of short term purchases from suppliers remote from our service area. No matter how attractive these one shot purchases are momentarily, reliance on these will, we believe, in the long run prove detrimental in terms of both reliability and cost as these supplies become constricted by growing demand on the suppliers' systems. This growth will come relatively quickly in relation to the lengthy utility planning horizon. Membership in a unified system of utilities, which support each other by the maintenance of sufficient capacity margins, is by far the wiser course. We would urge regulators not to devalue long term benefits. Seeking the current lowest cost, without regard to other considerations, may turn out to be very costly indeed in the long run.

CONCLUSION

With the recent completion of Grand Gulf Unit 1 and Waterford Unit 3, the Middle South System has achieved a major milestone in an extensive program of fuel diversification, consistent with national priorities and designed to reduce electricity costs over the long-term. At the time of severe curtailments of natural gas for power plant fuel in the early 1970's and of the Arab Oil Embargo in 1973, all of the System's steam-electric generating units were fueled with natural gas with oil as back-up fuel. Since then, we have completed four nuclear units and four coal units, our shares of which represent 3,923 megawatts of nuclear capacity and 1,894 megawatts of coal capacity. Thus, about 37 percent of the System's total installed capability is now in the form of coal and nuclear units.

After more than a decade and a half of working on this program of fuel diversification during one of the most difficult economic periods in our history, we now are confronted with the ultimate paradox. Largely because of similar fuel diversification programs throughout the world, gas and oil are now available in abundant supplies and current prices are substantially below those projected just a few years ago by all the experts we could find. Our actions are being attacked as imprudent and unnecessary. Yet, if utilities had not embarked on oil and gas displacement programs, these high price forecasts would probably have materialized and the same voices would now be criticizing us for imprudently relying upon high priced petroleum products.

We have been accused of trying to avoid regulation of Grand Gulf. Yet the record is clear that, since 1972, we have sought and received all requisite approvals. Three years transpired between the filing of the Unit Power Sales Agreement and the recent FERC decision. All interested parties diligently pursued their respective interests in the FERC proceedings. The System put forth settlement offers in January, 1985 and again in June, 1985, after the FERC decision, whereby the stockholders would absorb some of the Grand Gulf costs. None of the parties accepted these offers.

Given the fact that the MSU operating companies conduct business in separate states, and given the dual system of state and federal rate regulation, the positions of the parties can be conveniently grouped on a state-by-state basis. Each of the state/party groups shares a common view that customers in its own state should have less responsibility for the costs of Grand Gulf, while customers in the other states should have more cost responsibility.

A major problem confronting us and all electric utilities is the planning horizon associated with construction of generating facilities. Traditional utility planning considers "life-cycle economics" over a 30-40 year span. Yet, others tend to look only at short-term effects in assessing the wisdom of our decisions.

Contrary to widespread public belief, the use of electricity is still increasing--granted, not at the high levels of the 1950's and 1960's, but still at a respectable pace. Too many people erroneously equate this lesser rate of growth in electricity use as being a drop in electricity use.

Some of this confusion may be because non-electric energy use has fallen more than 15 percent since 1973. But during the same time frame, the use of electricity has actually gone up by more than 20 percent. Industrial use of total energy has decreased by 28 percent since the early 1970's. However, during the same period, the use of electricity by industry has increased by 16.6 percent. Clearly, our society is using less total energy today through conservation and the continued electrification of our homes and workplaces.

The growth in the Gross National Product is closely linked to similar levels of growth in the usage of electricity. GNP and electricity have had a strong correlation for the past several decades. When viewed on a graph, the two lines move almost in parallel--before 1973 when GNP grew at an average 4 percent a year, the use of electricity increased by an average of 7 percent a year. When GNP grew at 5 percent levels in the mid-1970's, so did electricity. And when GNP stagnated in the recent recession, the use of electricity also leveled off. Similarly, in 1984, when GNP rebounded to a 6.9 percent growth rate, electricity use increased nationwide about 6 percent. There are reports of some electric utilities having already experienced peak loads this year which they had not expected until late in the 1980's. Among our System companies only the smallest, New Orleans Public Service Inc., has not already exceeded its forecasted peak demand for 1985 and the hottest part of the year is normally yet to come at this point in time. LP&L has experienced a peak demand 3.7 percent above the highest level of all of 1984, and MP&L has exceeded its 1984 peak by 6.6 percent already.

Even at a growth rate of 2.5 percent annually, by the end of the century usage of electricity will have increased almost 50 percent. To meet that demand, the nation's utilities will need to build 300 more large generating plants than are currently under construction.

We believe there is very broad agreement among knowledgeable people that for sizable additions to electric generating capacity, coal and uranium are now the only two practicable fuels domestically available which are abundant and relatively stable in price and supply. But we must recognize that it takes an average of 8 years to design, build, and put into operation a coal-fueled plant and about 12 years or more for a nuclear plant in this country.

I have already mentioned the impending need for more generating capacity before the year 2000. What will also be needed before utilities will renew their construction programs and undertake the risks involved with lengthy construction lead times is the front-end involvement on the part of enlightened utility regulators who will measure the worth of such long-term decisions in context with the long-term benefits.

We all know that unless major changes are made, new nuclear plants are not likely to be started in this country, while the rest of the world marches forward on electricity from uranium. And some of the same problems constrain our decisions on non-nuclear base load plants as well, particularly coal plants. We cannot solve all the regulatory, financial and political problems that are restricting the utility industry's ability to install major new capacity in a vacuum; the positive steps that we need, especially on nuclear power, will require a broad base of understanding and support from legislators, regulators and the public.

The country needs to face up to this serious long-term dilemma: Electrical demand is growing in parallel with our GNP at the same time that the financial and regulatory climate is discouraging utilities from taking investment steps to meet that demand reliably and economically over the long-term. It is not just the utility industry that is being trapped between these pressures. Ultimately, it is our entire economy that could suffer.

1970-1971

"President Nixon, Members of Congress and Federal officials - all wanting to be on the right side of the environmental political issue - found themselves in the middle of the national power dilemma in 1970.

'The power shortage facing the nation, much like the shortage of clean land, air and water, has suddenly in the 1970s become a crisis rather than simply a nagging problem.

'In April, both the chairman of the Federal Power Commission, John N. Nassikas, and the President's science adviser, Dr. Lee A. DuBridge, warned the public that the power situation throughout the United States was critical and forecast power blackouts in various parts of the country in the summer of 1970.

'Nassikas predicted the summer months would bring the worst electric power shortage ever and said he could see no solution to the problem of inadequate power for perhaps a decade.

'A cooler summer than usual helped prevent serious blackouts, although some cities did experience 'brownouts,' where power intermittently had to be cut in specified areas.

'Both men claimed that the sudden concern over the environment had prevented the building of new power plants to keep pace with the rising demands for more power." (Page 523 -- 1970 Congressional Quarterly Almanac)

- In 1971 President Nixon proposed a major energy initiative to Congress calling for an adequate supply of clean energy. A major element of this program was nuclear power.

1972

- Concern over the sufficiency of U.S. energy sources - and a lack of a unified general energy policy - was evidenced during major congressional hearings during 1972. (Page 372 -- 1972 Congressional Quarterly Almanac)

- The Senate Commerce Committee held hearings on three Bills to help alleviate the nation's natural gas supply shortage. (Page 446 -- 1972 Congressional Quarterly Almanac)

- The Joint Economic Committee held hearings on natural gas and the Trans-Alaska Pipeline at which serious concerns were expressed about future natural gas supply. (Page 567 -- 1972 Congressional Quarterly Almanac)

1973*

- On October 18, 1973 the Arab oil producers imposed the oil embargo.

- Three weeks after the embargo President Nixon signed legislation (which had been under consideration before the embargo) directing him to impose a mandatory fuel allocation system on the nation.

- On November 7, 1983, President Nixon outlined to the American people his proposed "Project Independence" the purpose of which was to address anticipated acute shortages of energy and to reduce our dependence on foreign oil.

- Included in "Project Independence" were provisions to authorize the President to order power plants to switch from using oil to using coal. Also included were provisions to speed up the licensing of nuclear power plants.

- During 1973 the question of supply and price of natural gas continued to be argued. John Love, the director of the White House Office of Energy Policy, said that the average 22¢ price of natural gas was equivalent to a price of 72¢ for domestic oil and $1 for imported oil. The result he said was natural gas being inefficiently used by large industries and was often unavailable to the consumer. (Page 642 -- 1973 Congressional Quarterly Almanac)

1974*

- During 1974 two new energy agencies were created to administer federal energy policy. The Federal Energy Administration (FEA) was set up to manage federal efforts to deal with energy shortages (PL-93-275). Responsibilities included allocation of oil, gathering of energy data and conservation programs. The Energy Reorganization Act (PL-93-438) established the Energy Research and Development Administration (ERDA). It also abolished the Atomic Energy Commission and put in its place the Nuclear Regulatory Commission.

- The FEA was granted additional powers and responsibilities later in 1974 when Congress passed "ESECA" - the Energy Supply and Environmental Coordination Act (H.R. 14368 - PL-93-319). Under "ESECA" FEA had authority to prohibit the burning of oil or natural gas by utility power plants capable of using coal. Congress also directed FEA to require that new fossil plants be designed to use coal as a primary energy source.

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*Pages 131-143, Energy Policy - Second Edition, Congressional Quarterly, Inc.

1975

- President Ford's Energy Legislative Proposal included a provision to extend federal authority to order power plants to burn coal in place of oil or natural gas. (Page 174 -- 1975 Congressional Quarterly Almanac)

- Development of federally owned coal (almost half of the recoverable coal in the U.S.) remained at a standstill in 1975 as a four year old moratorium on new leases continued. (Page 176 -- 1975 Congressional Quarterly Almanac)

- The House/Senate Democratic leadership's alternative to President Ford's energy program proposed that coal conversion incentives should be provided to require new fossil-fuel-fired electric generating plants and heavy industrial boilers to burn coal, rather than oil or natural gas, and to encourage the conversion of existing plants to coal. (Page 195 -- 1975 Congressional Quarterly Almanac)

- S. 622, as passed by the Congress (12/17/75) and signed by the President, extended to June 30, 1977, from June 30, 1975, the authority of the Federal Energy Administration (FEA) to order power plants and other major fuel burning installations to convert from use of oil or natural gas to use of coal and extended the period for enforcement of these orders to December 31, 1984, from December 31, 1978. (Page 222 -- 1975 Congressional Quarterly Almanac)

- On September 23, 1975, the House passed H.R. 7014 Title VI of which addressed fuel conversion. Its provisions were as follows:

  - Extended the coal conversion authority of FEA for two years, to June 30, 1977, for issuing orders directing conversion. Extended the period within which these orders could be enforced for six years, to December 31, 1984 from December 31, 1978; expanded the categories of plants to which coal conversion orders could be issued.

  - Authorized FEA to prohibit power plants to use natural gas as boiler fuel and to order them to convert to oil under certain conditions. (Page 235 -- 1975 Congressional Quarterly Almanac)

- During House debate on H.R. 7014 an argument was made that the authority being given FEA to order conversion to coal could bankrupt every utility in the Southwest and an amendment was offered to strike this authority from the FEA. The amendment to strike was defeated by a vote of 93 to 300. (Page 239 -- 1975 Congressional Quarterly Almanac)

(1975 continued)

- During 1975 several Bills addressing natural gas deregulation were debated in the Congress. (Page 252 -- 1975 Congressional Quarterly Almanac)

- On June 12, 1975 the Senate Commerce Committee reported a Bill (S. 692 - Senate Report 94-191) intended as an alternative to President Ford's call for natural gas deregulation. In addition to a complex proposal on gas pricing it also included the following provision on conservation of natural gas:

  . Directed the Federal Power Commission to ban as soon as practicable the use of natural gas as boiler fuel by plants for whom it was not initially contracted before 1975, with the aim of phasing out entirely within ten years the use of natural gas for boiler fuel by users other than residential and small users.

  . Gave special priority, in the event of interruption or curtailment, to agricultural and food processing uses of natural gas.

- On October 22, 1975 the Senate reported and sent to the House a Natural Gas Bill - S. 2310 - which was different from the Commerce Committee's Bill, S. 692. In addition to emergency shortage and pricing provisions it also included the following:

  . Authorized the Federal Energy Administration (FEA) to ban the use of natural gas as boiler fuel for generation of electricity.

  . Extended for one year, to June 30, 1976, the power of FEA (under the Energy Supply and Environmental Coordination Act of 1974) to order plants to convert from use of natural gas and other petroleum products to coal. (Page 258 -- 1975 Congressional Quarterly Almanac)

1976

- "America's energy crisis worsened in 1976. Three years after President Nixon called for a total commitment to make the United States energy independent, this country was more dependent than ever upon foreign powers for fuel." (Page 91 -- 1976 Congressional Quarterly Almanac)

- During 1976 America's dependence on foreign oil approached 40%.

- President Ford again proposed an energy program including natural gas deregulation and re-emphasized the need for greater utilization of nuclear energy. (Page 92 -- 1976 Congressional Quarterly Almanac)

- The legislation which the House of Representatives passed dealing with natural gas (H.R. 9464) contained, among others, the following provisions on natural gas conservation:

  - Directed the FPC to prohibit boiler-fuel use of natural gas not contracted for before January 1, 1976 with certain saving provisions.

  - Directed the FPC to prohibit boiler-fuel use of natural gas sold under existing contracts when the contracts expire or within 10 years.

- The Senate Commerce Committee reported a Bill (S. 3422) on natural gas similar to its 1975 proposal. S. 3422 included provisions to phase out over 10 year the use of natural gas for generating electricity and to require boiler fuel users to bear the bulk of higher natural gas prices. (Pages 174-175 -- 1976 Congressional Quarterly Almanac)

- The Congress passed legislation extending the life of FEA for 18 months. It broadened the powers of FEA in many areas. (Pages 100-101 -- 1976 Congressional Quarterly Almanac)

1977

- President Carter's National Energy Plan was the major energy proposal during 1977. Congress worked on it from May through December but was unable to complete action. The House passed one omnibus Bill (H.R. 8444) and the Senate passed five different Bills.

- The severe winter of 1977 caused the Emergency Natural Gas Act of 1977 to be passed in less than a week.

- On July 21, 1977 President Carter signed the Bill S. 1468 (PL-95-70) extending the life of FEA through fiscal 1978. The legislation extended FEA authority to order certain utility and industrial facilities to convert to coal. (Page 661 — 1977 Congressional Quarterly Almanac)

- The Carter National Energy Plan, among many other features, proposed to levy stiff taxes against businesses that burned oil or natural gas and against purchasers of domestically produced oil. The proposal also prohibited the construction of new oil or gas fired boilers. The taxes were aimed at spurring energy conservation and their effect would have been to drive up energy prices. (Page 708 -- 1977 Congressional Quarterly Almanac) Note: The impact of the proposed tax on oil and gas on MSU system customers was estimated to be $1 billion.

- As passed by the House, H.R. 8444 contained, among other things, provisions for conservation, natural gas pricing, utility rate reform, crude oil equalization tax and coal conversion. Some of the coal conversion provisions were as follows:

  . Prohibited new oil or gas fired utility power plants.

  . Ordered all existing utilities to cease burning natural gas by 1990. (Page 725 -- 1977 Congressional Quarterly Almanac)

1978*

- Energy policy legislation cleared Congress on October 15, 1978, 18 months after introduction. The five part package contained legislation addressing natural gas, coal conversion, utility rates, conservation and taxes.

- The Powerplant and Industrial Fuel Use Act of 1978 (PL-95-617) addressed coal conversion. Under its provisions no new oil or gas fired electric utility boilers could be built. Existing utility plants using oil or gas were to switch to other fuels by 1990. Existing gas fired utility boilers were restricted in the amount of gas they could use in the future to an amount determined by their average usage during a historical base period. (Middle South Utilities' operating companies were under natural gas curtailment orders during the legislated base period and consequently were severely impacted by this provision.

1979

- "The cost of energy for the United States, in terms of dollars, national security and environmental concerns, continued to rise in 1979.

  Oil prices increased at a staggering rate, reflecting disruption in oil markets and worldwide political uncertainty. During the year, the world price climbed from $16 to $30 per barrel." (Page 601 -- 1979 Congressional Quarterly Almanac)

- As a result of increased pressure on oil supply and pricing, early in April of 1979 President Carter directed the Energy Department to continue to make it easier for utilities and major industrial users to switch from oil to natural gas because of the then existing surplus of gas (gas bubble). (Page 609 -- 1979 Congressional Quarterly Almanac) Note: This was accomplished through the use of public interest exemptions.

- In July of 1979, President Carter asked Congress to pass legislation requiring electric utilities to cut their oil consumption by 50% by 1990. (Page 609 -- 1979 Congressional Quarterly Almanac)

- Notwithstanding concern over nuclear safety that followed the Three Mile Island accident, both Chambers of Congress in 1979 decisively rejected proposals to impose a six month moratorium on permits for constructing new nuclear power plants. (Page 213 -- Energy Policy, Second Edition, Congressional Quarterly, Inc.

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*Energy Policy - Second Edition - Congressional Quarterly, Inc.

1980

- "Americans continued to grow more aware of the value of energy in 1980. Conservation became increasingly profitable as prices of gasoline, electricity, heating oil and natural gas kept rising -----

- Much of Congress' year in the energy field was spent finishing what it started in 1979 -- taxing hugh oil profits and putting the government into the synthetic fuel business." (Page 471 -- 1980 Congressional Quarterly Almanac)

- 20,000 coal workers were out of work as 1980 ended. The coal industry blamed its problems on a combination of transportation difficulties and environmental restrictions. (Page 472 -- 1980 Congressional Quarterly Almanac)

- The Senate passed legislation to provide $3.6 billion in government subsidies to convert oil-fired electrical generating plants. The Bill also contained a provision to repeal the requirement that utilities stop burning gas by 1990. The Bill died in the House. (Page 472 -- 1980 Congressional Quarterly Almanac)

- "Acid Rain" surfaced as a new major environmental concern in the use of coal as a fuel.

- The nuclear power industry continued to suffer the effects of the 1979 TMI incident.

1981

- "In a year without significant energy shortages, the national energy focus shifted from massive government programs to individual initiatives..." "For the first time since the 1973 Arab oil embargo, Congress did not debate any substantial new energy programs." (Page 439 -- 1981 Congressional Quarterly Almanac)

- World oil prices dropped slightly during the year, although substantial increases had been predicted. The $50/barrel price predicted for the spring of 1981 never materialized. Increased conservation around the world helped create a world oil glut. (Page 439 -- 1981 Congressional Quarterly Almanac)

- During 1981 the provision of the Fuel Use Act of 1978 which prohibited the use of gas in electric utility boilers in 1990 and limited its use before then was repealed in the Budget Reconciliation process. (Page 449 -- 1981 Congressional Quarterly Almanac)

ATTACHMENT 2

GRAND GULF UNIT 1

VARIOUS ALLOCATIONS IN PERCENT

	UPSA 6/10/82	Judge Liebman 2/3/84	Judge Head 2/4/85	FERC Opinion No. 234 6/13/85
AP&L	-0-	36.00	32.93	36.00
LP&L	38.57	14.00	42.69	14.00
MP&L	31.63	33.00	14.90	33.00
NOPSI	29.80	17.00	9.48	17.00

NOTES:

(1) The Unit Power Sales Agreement (UPSA) filed with the FERC in June 1982, also included a proposed allocation of Grand Gulf Unit 2; however, the decisions by Judges Liebman and Head and FERC Opinion No. 234 did not include an allocation of this unit.

(2) Judge Head did not define specific allocation figures but recommended that the allocation should be based on the prior year's ratios of each company's annual demand to the System's annual demand. The figures shown represent the companies' 1984 energy requirements as percentages of the total System's energy requirements.

(3) The percentages shown apply to MSE's 90% interest in Grand Gulf Unit 1.

GRAND GULF CONSTRUCTION AUDIT

Executive Summary

Prepared for

MISSISSIPPI PUBLIC SERVICE COMMISSION

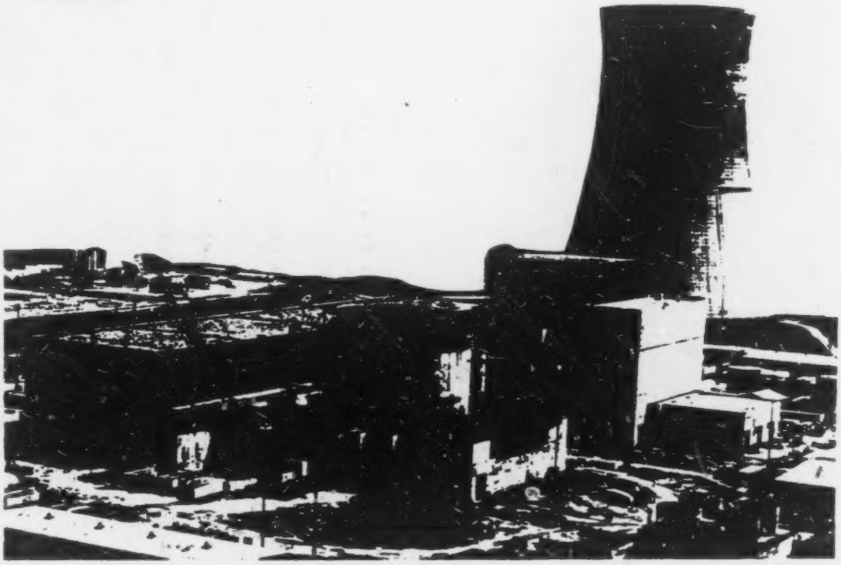
●

Jointly Prepared By

DECISION MANAGEMENT COMPANY, INC.
Laguna Hills, California
and

BURKHALTER & COMPANY
Jackson, Mississippi

APRIL, 1985



INTRODUCTION

Mississippi Power & Light Company (MP&L), an operating company of Middle South Utilities, Inc. (MSU), provides electricity to 45 counties in western Mississippi. To meet the forecasted demand for electric power in the early 1980's, MP&L and its sister companies made a joint decision in 1970 to construct the Grand Gulf Nuclear Station (GGNS). GGNS consists of two 1250 MWe boiling water reactor units. Unit 1 received its Full Power Operating License in August, 1984, and Unit 2 is presently under construction.

In August, 1984, the Mississippi Public Service Commission issued a Request for Proposal (RFP) inviting independent management consulting firms to conduct a construction audit of GGNS. The RFP identified the following four principal objectives for the audit:

- Develop increased understanding of causes of cost escalation and schedule slippage;
- Determine specific effects each causal factor identified above had on construction cost and schedule slippage;
- Determine MP&L's ability to control each of these factors; and
- Determine the overall performance of MP&L in planning, engineering, construction and licensing of GGNS.

The RFP stated that the principal audit objectives should be achieved through review and evaluation of 66 specific issues.

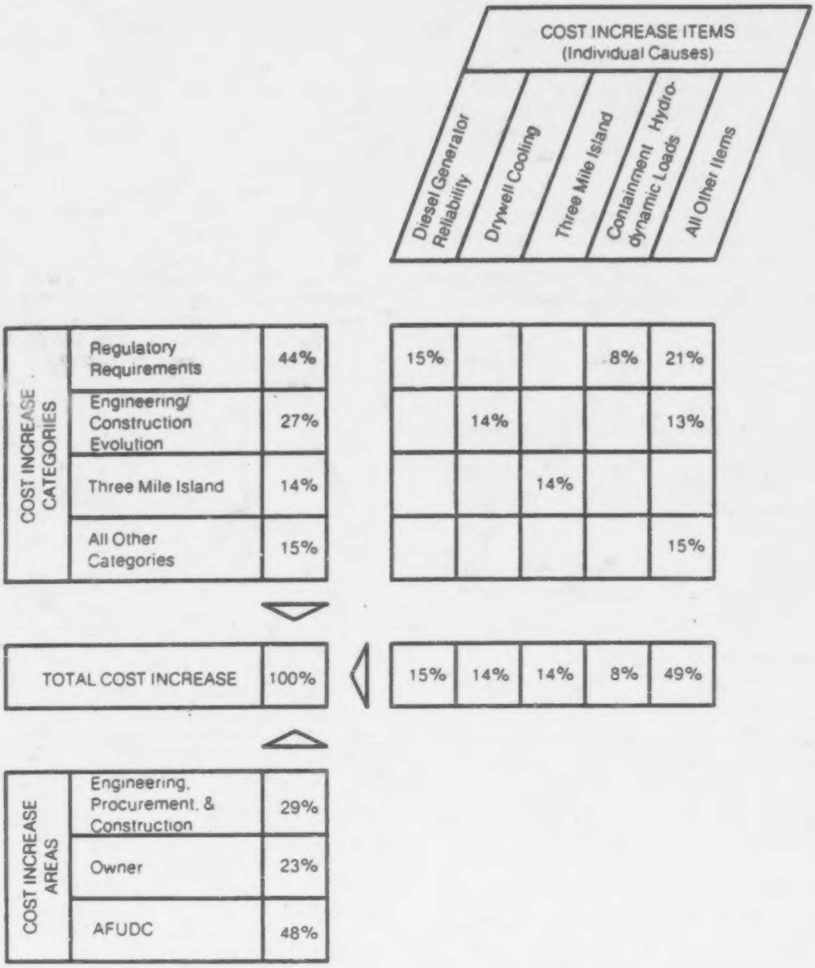
On September 26, 1984, the Commission selected Burkhalter & Company of Jackson, Mississippi and Decision Management Company, Inc. of Laguna Hills, California to conduct the audit and prepare a report on GGNS construction. The audit began in October, 1984, and was completed in April, 1985.

As requested by the RFP, the construction audit was directed at providing a comprehensive assessment of Grand Gulf Unit 1, especially in regard to MP&L's management performance. It should be noted, however, that this assessment also applies to Unit 2, to the extent this unit has been designed and constructed.

This document is an executive summary of the results of the construction audit which are substantiated in a detailed three-volume report. The executive summary focuses on the findings and conclusions of the audit with respect to the RFP principal objectives. In addition, the executive summary includes, as an appendix, an overview of the nuclear power industry that places our findings and conclusions in perspective.

Our analysis of GGNS construction is based upon the most recent data available at the time the audit commenced in October, 1984. The latest official cost and schedule information for GGNS Unit 1 available at that time was that presented in the May, 1984 forecast. This information is referred to as the most current and used for analysis in all but one section of this report. In the industry comparison section, the cost of GGNS Unit 1 presented in the September, 1983 forecast was used in order to coincide with the most recent industry data available.

Figure 1
Anatomy of GGNS Cost Escalation



COST INCREASE CATEGORIES		Diesel Generator Reliability	Drywell Cooling	Three Mile Island	Containment Hydrodynamic Loads	All Other Items
Regulatory Requirements	44%	15%			8%	21%
Engineering/ Construction Evolution	27%		14%			13%
Three Mile Island	14%			14%		
All Other Categories	15%					15%
TOTAL COST INCREASE	100%	15%	14%	14%	8%	49%

COST INCREASE ITEMS
(Individual Causes)

COST INCREASE AREAS	
Engineering, Procurement, & Construction	29%
Owner	23%
AFUDC	48%

FINDINGS AND CONCLUSIONS

The following are the primary findings and conclusions of the Grand Gulf construction audit with respect to the four principal objectives listed in the Request for Proposal:

Factors Causing Cost Escalation and Schedule Slippage

- In general, all significant cost and schedule increases on Grand Gulf were due to factors associated with the growth of the nuclear power industry during the 1970's and early 1980's and not to factors unique to the project itself.
- Specifically, cost and schedule increases on Grand Gulf were primarily due to changes and additions in regulatory requirements, engineering and construction evolution over the course of the project and the impact of the accident at Three Mile Island (TMI).

Specific Effects of Factors Causing Cost Escalation and Schedule Slippage

- The cumulative effect of factors causing cost escalation was a $2570 million increase in the total cost of Grand Gulf Unit 1 between the definitive and most current cost estimates. The current total cost of Unit 1 is $3424 million.
- The cumulative effect of factors causing schedule slippage was a 62-month delay in commercial operation of Grand Gulf Unit 1 between the definitive and most current schedules. The current commercial operation date of Unit 1 is March, 1985.
- The categories (**Figure 1**) accounting for the majority of the cost increases were changes and additions in regulatory requirements (44%), engineering and construction evolution (27%), and the impact of TMI (14%). These three categories collectively accounted for 85 percent of the total cost increase.
- The individual items accounting for the greatest cost increases were reliability problems with the diesel generators, the impact of TMI, insulation problems in the containment drywell, and the design for handling hydrodynamic loads. These four individual items, collectively, accounted for over 50 percent of the increase in cost.
- Allowance for Funds Used During Construction (AFUDC) was the cost area which increased most. This area, alone, comprised nearly 50 percent of the total cost increase.
- While AFUDC accounted for the largest absolute cost increase, owner cost grew by the greatest percentage.

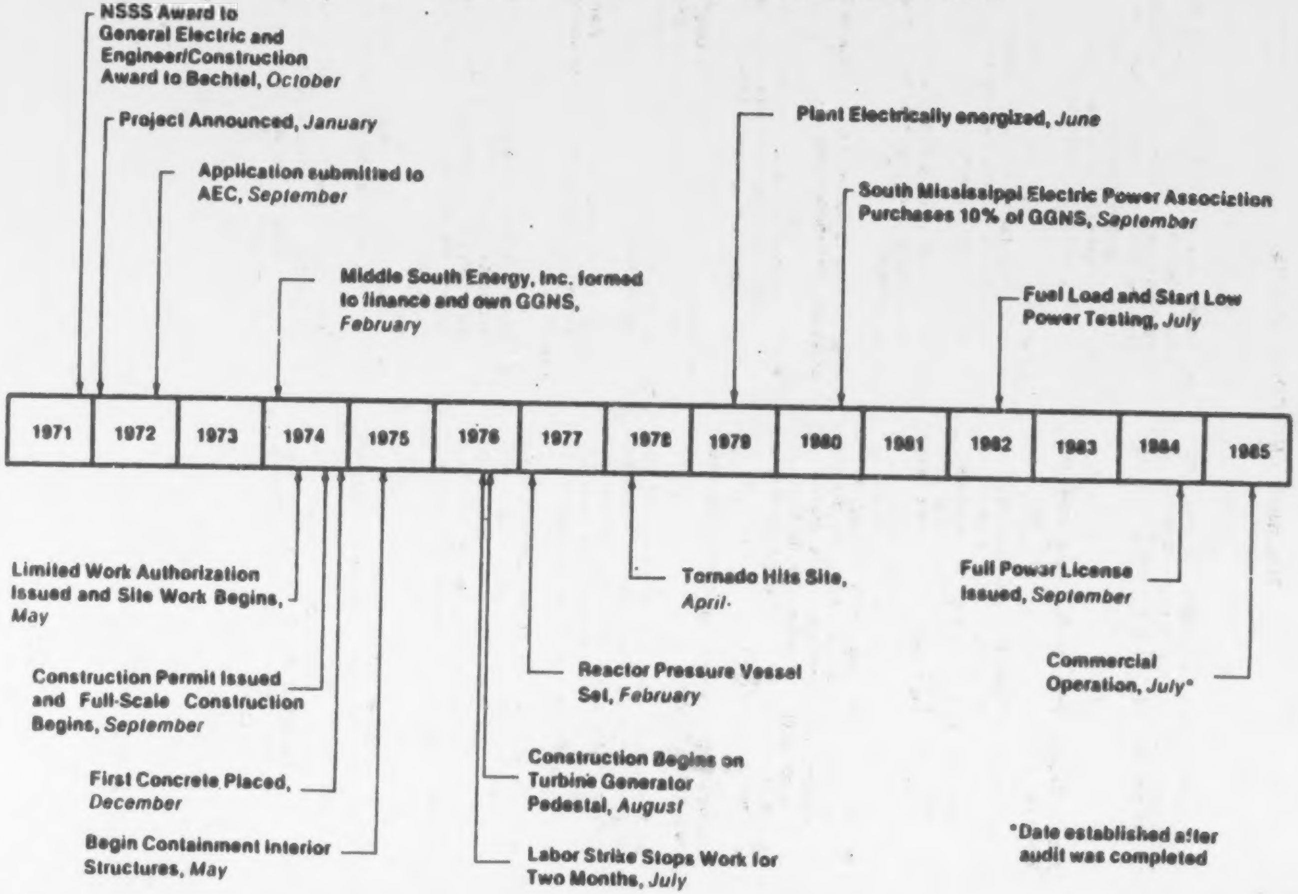
MP&L's Ability to Control Factors Causing Cost Escalation and Schedule Slippage

- Factors causing major cost escalation and schedule slippage were industry-wide in nature and beyond the direct control of MP&L.
- Review of the project indicates that MP&L took measures to minimize the cost and schedule effects of industry-wide events and other impacting factors.

Overall Performance of MP&L in Planning, Engineering, Construction and Licensing of Grand Gulf

- While a number of project activities were performed by others, MP&L adequately planned, participated in and managed these activities, and met the evolving needs and demands of Grand Gulf.
- Overall, MP&L's performance in major project activities was at least equal to the industry norm.
- By most measures, the cost and schedule of Grand Gulf Unit 1 compare adequately against those of similar nuclear units constructed during the same time frame.

Figure 2
Chronology of Key Events for Grand Gulf Unit 1


NSSS Award to General Electric and Engineer/Construction Award to Bechtel, *October*
Project Announced, *January*
Application submitted to AEC, *September*
Middle South Energy, Inc. formed to finance and own GGNS, *February*
Plant Electrically energized, *June*
South Mississippi Electric Power Association Purchases 10% of GGNS, *September*
Fuel Load and Start Low Power Testing, *July*
1971
1972
1973
1974
1975
1976
1977
1978
1979
1980
1981
1982
1983
1984
1985
Limited Work Authorization Issued and Site Work Begins, *May*
Construction Permit Issued and Full-Scale Construction Begins, *September*
First Concrete Placed, *December*
Begin Containment Interior Structures, *May*
Tornado Hits Site, *April*
Reactor Pressure Vessel Set, *February*
Construction Begins on Turbine Generator Pedestal, *August*
Labor Strike Stops Work for Two Months, *July*
Full Power License Issued, *September*
Commercial Operation, *July**

*Date established after audit was completed

COMPANY / PROJECT HISTORY

Company

Mississippi Power & Light Company was originally formed in 1923 to acquire the municipally-owned utility properties of Jackson and three neighboring towns, with the intent of providing central station service. Today, MP&L supplies electricity to 45 counties in western Mississippi and is a principal operating subsidiary of Middle South Utilities, Inc. (MSU).

MP&L built and installed a 30 MW plant in 1948. By 1971, the Company had placed nine gas-fired units into service. In late 1970, however, the fact that natural gas supplies were scarce and becoming even more limited prompted the Federal Power Commission to limit the amount of gas that could be supplied for electric power generation. As a result, MP&L realized it must begin to investigate alternate sources of fuel for power generation.

During the late 1960's and early 1970's, the area served by MP&L was experiencing considerable economic growth. Electricity consumption was also increasing at a significant rate. With the acceleration of industrial and business development expected in the years ahead, the forecast in the early 1970's was for continued annual increases in electricity sales.

It was in the context of expanding electricity demands and the need to diversify its fuel base that MP&L, in January of 1972, announced its intention to build the Grand Gulf Nuclear Station. The chronology of major events in the history of GGNS is shown in **Figure 2**, and the key project facts are outlined opposite.

Key Project Facts

Ownership

- Middle South Energy, Inc. (90%)
- South Mississippi Electric Power Association (10%)

Agent for Construction and Operation

- Mississippi Power & Light Company

Capacity

- Unit 1 - 1250 MWe
- Unit 2 - 1250 MWe

Nuclear Steam Supply System

- General Electric Boiling Water Reactor (BWR)

Turbine Generator

- Allis-Chalmers Power Systems, Inc.

Location

- 25 miles south of Vicksburg, at Port Gibson, Mississippi (on the Mississippi River)

Engineer/Contractor

- Bechtel Power Corporation

Project Cost (including AFUDC)

- Unit 1 - $3424 million
- Unit 2 - $927.6 million (expended as of December 31, 1984)

Figure 3a
Increase in Total Cost

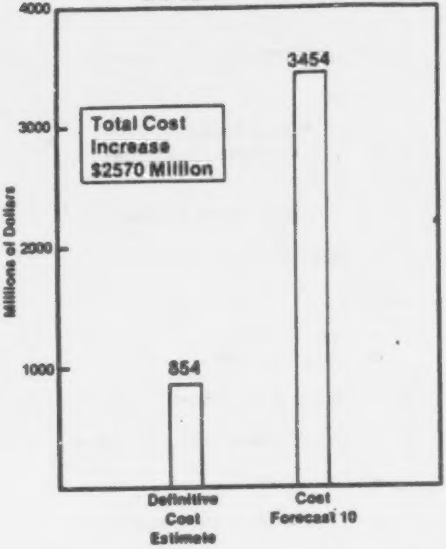


Figure 3c
Increase in Schedule

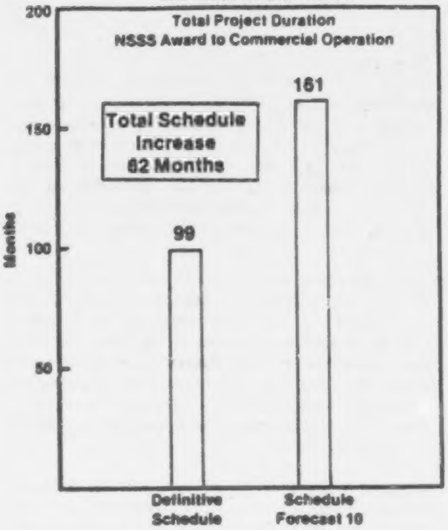
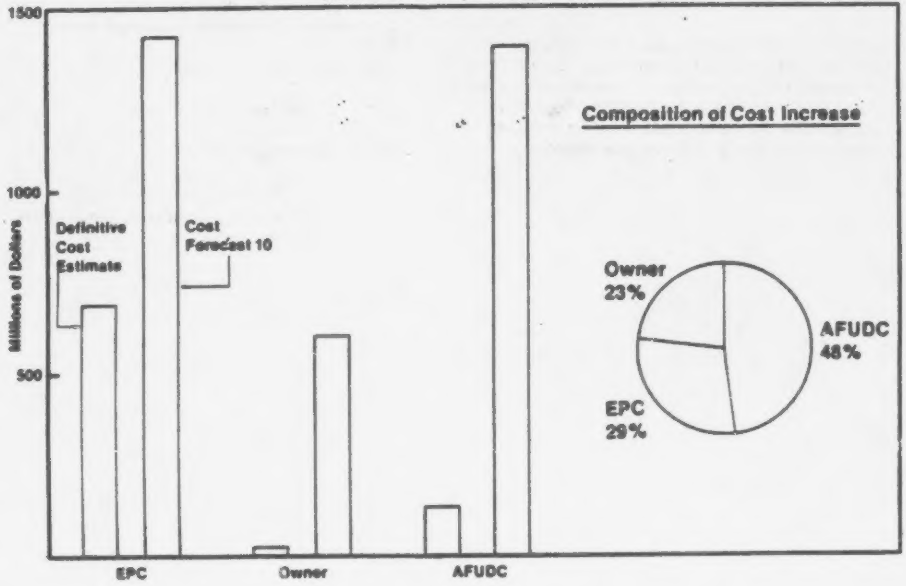


Figure 3b
Increase in Major Cost Areas



INCREASES IN COST AND SCHEDULE

The following is a summary and quantification of the increases in cost and schedule that have occurred since the Definitive Cost Estimate and Definitive Schedule were issued in December, 1974. The Definitive Cost Estimate was the first estimate sufficiently advanced to reflect the actual cost of Unit 1 with a reasonable degree of accuracy; the Definitive Schedule was the first detailed schedule to support the commercial operation date. Both served as the baselines against which future revisions were measured.

Cost

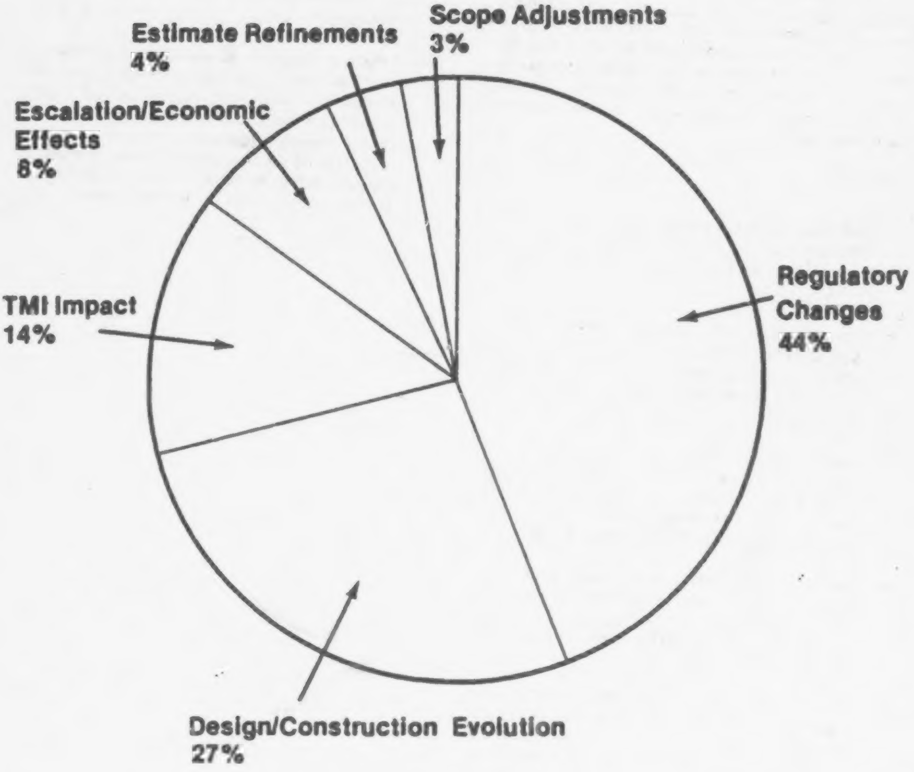
- The total cost of Grand Gulf Unit 1, most recently estimated in May of 1984, in Cost Forecast 10, has been revised ten times since December of 1974.
- Cost Forecast 10 indicates a total cost of $3424 million. This amount is $2570 million higher, or 300 percent greater, than the $854 million cost shown in the Definitive Cost Estimate **(Figure 3-a).**
- Substantial increases were incurred during the project in each of the three major cost areas–Engineering, Procurement and Construction (EPC); Owner Cost; and Allowance for Funds Used During Construction (AFUDC) **(Figure 3-b).**
- The largest absolute cost increase occurred in AFUDC, which escalated by $1260 million (from 16 to 41 percent of the total Unit 1 cost). This increase accounted for nearly 50 percent of the total cost increase.
- The area which experienced the greatest relative increase was Owner Cost. This area increased from $28 million in the Definitive Cost Estimate to $605 million in Cost Forecast 10, constituting 23 percent of the total cost increase. As a result, Owner Cost represented 17 percent of Unit 1 cost in Cost Forecast 10, up from three percent in the Definitive Cost Estimate.

Schedule

- The commercial operation date and total project duration of Unit 1, most recently updated in May of 1984, in Schedule Forecast 10, have been revised seven times since the Definitive Schedule.
- Schedule Forecast 10 indicates a commercial operation date for Unit 1 of March, 1985, and a total project duration, from nuclear steam supply system contract award to commercial operation, of 161 months **(Figure 3-c).** This is 62 months longer, or 63 percent greater, than the duration indicated in the Definitive Schedule, which showed a commercial operation date of January, 1980.

Figure 4

Cost Increase Categories



CAUSES FOR INCREASES IN COST AND SCHEDULE

The cost accrual system utilized on Grand Gulf accumulated costs against the Federal Energy Regulatory Commission's code of accounts for financial reporting, and the Architect/Engineer's code of accounts for project control. The system did not accrue costs against events causing cost increases. Therefore, to determine the causes of cost and schedule increases, a review of these increases was conducted in relation to specific events that occurred throughout the duration of the project. This review was based on actual engineering and construction information, as well as estimates, studies and other documents prepared when cost and schedule revisions were made. The causes of cost and schedule escalation identified during this review were grouped into six major categories.

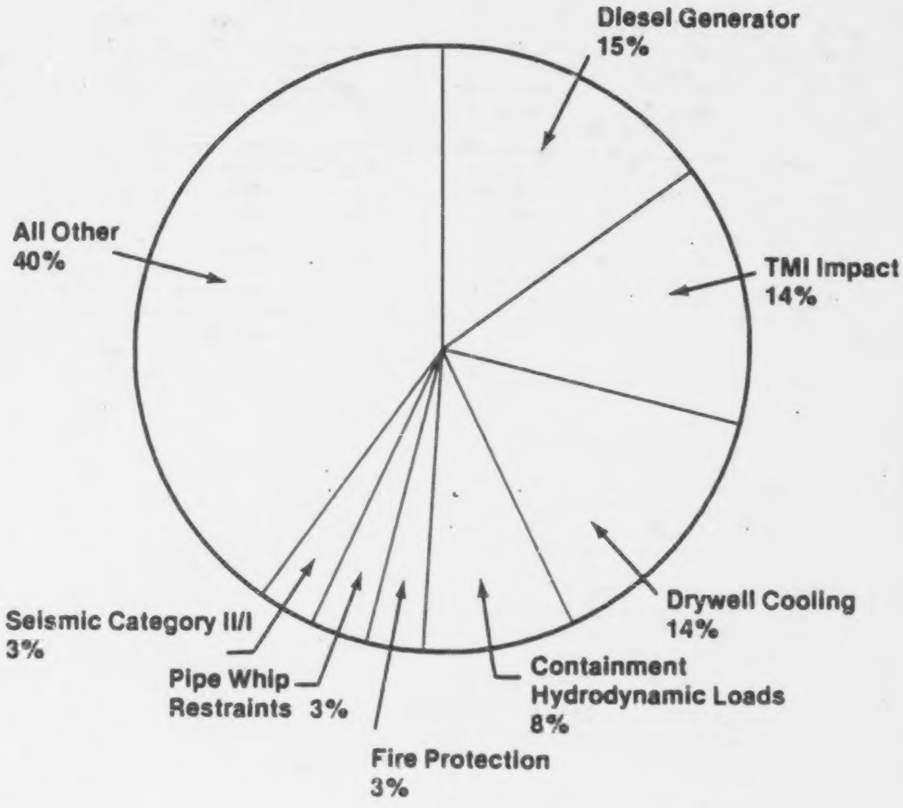
Categories of Cost and Schedule Increases

The causes of cost and schedule increases on GGNS Unit 1 fall within the following six categories:

- **Regulatory Changes**—effects of new or revised regulations issued by the Nuclear Regulatory Commission (NRC) and other agencies, as well as the effects of new industry standards
- **Design/Construction Evolution**—effects of normal, state-of-the-art developments over the course of the project in the scope of engineering and construction
- **TMI Impact**—effects of the accident at Three Mile Island, including new regulations, the licensing moratorium and the changed environment of the nuclear power industry
- **Escalation/Economic Effects**—effects of changes in economic conditions during the project, as well as the effects of force majeure
- **Estimate Refinements**—the cost of additional owner-provided materials, equipment and services which were underestimated or omitted in the Definitive Cost Estimate, but which were necessary to meet normal project requirements
- **Scope Adjustments**—effects of items added to the Definitive Cost Estimate at MP&L's discretion with the intent of enhancing plant operability and maintainability

Of these six categories, Regulatory Changes had the greatest impact on cost, accounting for 44 percent of the total increase (**Figure 4**). The second greatest impact was due to Design/Construction Evolution (27 percent), followed by TMI Impacts (14 percent). The remaining three categories, collectively, amounted to only 15 percent of the total cost increase.

Figure 5
Cost Increase Items



CAUSES FOR INCREASES IN COST AND SCHEDULE

(Continued)

Items Causing Cost and Schedule Increases

In terms of individual items, four events accounted for 50 percent of the total cost increase of GGNS Unit 1 (**Figure 5**).

- **Diesel Generator** (regulatory changes)—In August of 1983, a diesel crankshaft failed during the reliability testing of a Transamerica DeLaval, Inc. (TDI) standby diesel generator at the Shoreham nuclear plant. This event, the latest in a series of problems on TDI units, raised NRC concerns regarding the reliability of all TDI generators, including those at GGNS. The resolution of this industry-wide problem and the ensuing testing and modification of the GGNS diesel generators during the pre-operations phase added $384 million to the cost of Unit 1 and delayed commercial operation by 12 months.
- **TMI Impact**—The accident at Three Mile Island in March of 1979 caused the NRC to issue a series of new regulations to prevent the recurrence of a similar event. These regulations, issued when GGNS Unit 1 was well into the construction/start-up phase, had a sweeping effect on numerous plant structures and systems under construction or already built. The required modifications added $368 million to the cost of Unit 1 and delayed commercial operation by ten months.
- **Drywell Cooling** (design/construction evolution)—During non-nuclear heat-up on GGNS, design temperatures could not be maintained throughout the containment drywell because the insulation and heat removal system were not adequate. System modifications undertaken to improve the performance of insulation and provide requisite cooling capacity delayed commercial operation by 11 months and added $362 million to the cost of Unit 1.
- **Containment Hydrodynamic Loads** (regulatory changes)—On a BWR such as GGNS, a normal or accidental discharge of pressurized steam into the containment imposes hydrodynamic loads upon structures and components inside the containment. The methods for determining these loads, and the resulting requalification of equipment and components inside the containment, underwent continuous change and licensing review from 1972 to 1982. This increased the cost of Unit 1 by $203 million and delayed commercial operation by six months.

The next three factors that most impacted cost—Fire Protection, Pipe Whip Restraints and Seismic Category II/I requirements—were also caused by regulatory changes. These factors, collectively, accounted for nine percent of the cost increase, or $222 million, and added six months to the schedule of Unit 1.

The three individual items that had the greatest impact on cost and schedule—Diesel Generator, TMI Impact, and Drywell Cooling—all occurred well into the project, after considerable amounts of both engineering and construction had been completed. As a result, much of the cost increase was associated with modifying and retrofitting completed work.

Figure 6

Event Initiation and Cost Impact

		Initiation of Events Impacting Costs	
		Outside MP&L's Control	Within MP & L's Control
Degree of Cost Impact	High	● Diesel Generator ● TMI Impact ● Drywell Cooling	
	Medium	● Containment Hydrodynamic Loads ● Three Other Regulatory Changes ● Escalation/Economic Effects	
	Low		● Estimate Refinements ● Scope Adjustments

RESPONSIBILITY FOR COST AND SCHEDULE INCREASES

Responsibility assessments were conducted for four major events and four categories of events which, collectively, accounted for over 70 percent of the total cost and schedule increase (**Figure 6**). To assess responsibility, we endeavored to determine (1) who (or what) was responsible for initiating impacting events and the attendant cost and schedule increases and (2) whether MP&L's management of these events compounded the cost and schedule impact. The following is a summary of our findings and conclusions:

Event Initiation

Diesel Generator—This event was initiated by the diesel generator manufacturer and propagated by the NRC. Responsibility for the major portion of the cost and schedule increase associated with this event is directly attributable to the NRC's decision to address the issue of diesel generator reliability on a generic basis, rather than to consider the specific facts relating to the GGNS units. The manufacturer of the diesel generators bears responsibility for the direct cost of additional inspection and testing of the units that resulted from specific problems found in the GGNS diesel generators.

TMI Impact—This event was initiated by the NRC's response to the severe accident at the Three Mile Island nuclear station. Responsibility for the cost and schedule increase associated with this event is directly attributed to the new regulatory requirements issued during the post-TMI era.

Drywell Cooling—Drywell cooling problems resulted from the limitations of then-existing engineering techniques for determining insulation performance. As a result, no party bears responsibility for cost and schedule increases associated with this event.

Containment Hydrodynamic Loads—This event was initiated by various incidents in operating BWR plants and propagated by NRC requirements for additional load definition and analysis of the GGNS containment. Responsibility for the cost and schedule increase associated with this event is attributable to the new regulations promulgated to address the issue.

Three Other Major Regulatory Changes: Fire Protection, Pipe Whip, Seismic Category II/I—These events and the associated cost and schedule increases were caused by new regulatory requirements issued by the NRC during the 1970's.

Escalation/Economic Effects—Due to the nature of these events (tornado, labor strike, material escalation, etc.), the corresponding cost increases were, in general, outside the direct control of MP&L.

Estimate Refinements—These cost increases were due to MP&L's underestimation of the total owner scope at the time the Definitive Cost Estimate was made. The lack of estimating accuracy was the result of difficulties associated with estimating new technologies and the changing regulatory climate. Such difficulties were typically encountered by utilities during the past decade.

Scope Adjustments—While MP&L was directly responsible for the addition of certain items to the project scope and, consequently, for the associated cost increases, the Company added items with the intent of reducing operating and maintenance costs. The addition of such items is a result of normal project evolution.

MP&L Management of Impacting Events

MP&L's management of the above events did not compound their cost and schedule impact. These events were managed in the same manner as all other major project activities. As our analysis of MP&L's management practices indicates adequate performance in all major functional areas, the same conclusion is reached regarding MP&L's management of impacting events.

Figure 7a

Cost Comparison with Industry

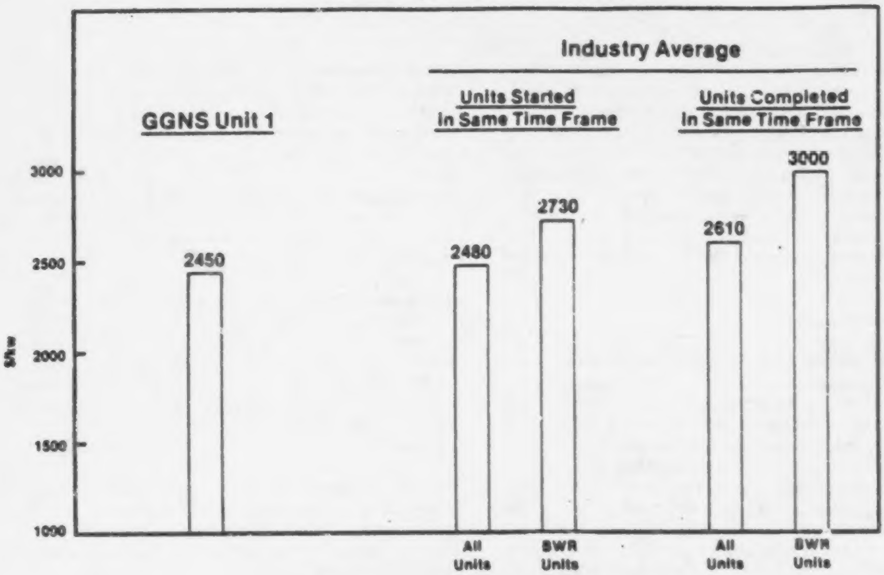
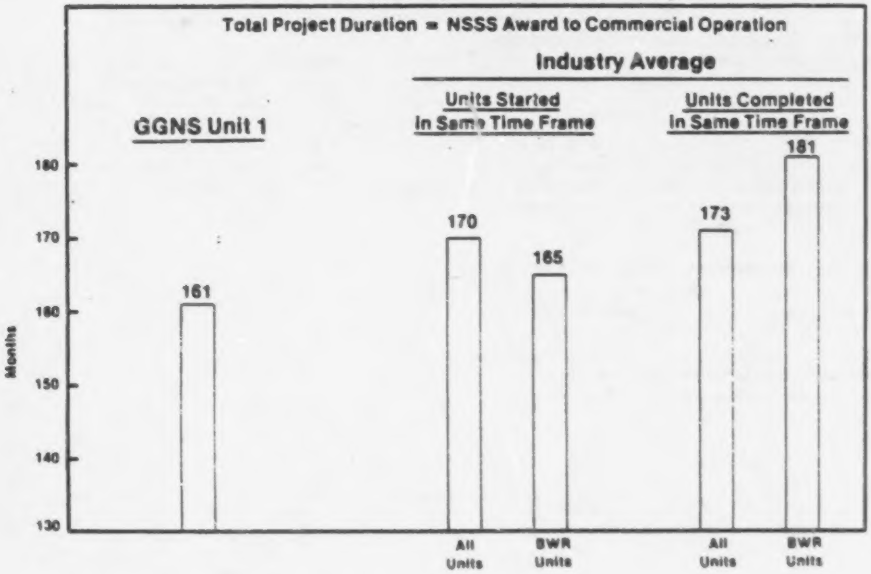


Figure 7b

Schedule Comparison with Industry



COST AND SCHEDULE COMPARISON WITH INDUSTRY

The following presents comparisons of the cost and schedule performance of Grand Gulf Unit 1 against other nuclear units constructed during the same time period.

Cost

The cost of GGNS Unit 1 presented in Cost Forecast 9 (issued in September, 1983), coincides with the most recent industry data available. For that reason, Cost Forecast 9 was selected as the basis for comparative analysis.

The cost of GGNS Unit 1 compares adequately against industry averages from a number of standpoints. Of nine cost comparisons, the cost of Unit 1 is less than the industry average for eight and greater than the industry average for one. The following presents the results of the four comparisons we regard as most meaningful (**Figure 7-a**):

- For units whose design and construction began (NSSS Award) within the same time frame as GGNS Unit 1, the cost of Unit 1:
  - is one percent below the industry average for all units, including both Pressurized Water Reactors (PWR) and Boiling Water Reactors (BWR)
  - is ten percent below the industry average for BWR units
- For units which have a completion date (commercial operation) within the same time frame as GGNS Unit 1, the cost of Unit 1:
  - is six percent below the industry average for all units
  - is 18 percent below the industry average for BWR units

Schedule

The schedule of GGNS Unit 1 used for this comparison is based on that presented in Schedule Forecast 10 (issued in May, 1984), which coincides with the most recent industry data available.

The Unit 1 schedule also compares adequately against industry averages from a number of standpoints. Of 12 schedule comparisons, the schedule of GGNS is shorter than the industry average for nine, and longer than the industry average for one. The four most meaningful comparisons are summarized in the following (**Figure 7-b**):

- For units which began in the same time frame as Unit 1, the total project duration (NSSS award to commercial operation) of Unit 1:
  - is five percent less than the industry average for all units
  - is two percent less than the industry average for BWR units
- For units which were or will be completed within the same time frame as GGNS Unit 1, the total project duration of Unit 1:
  - is seven percent less than the industry average for all units
  - is 11 percent less than the industry average for BWR units

AN ASSESSMENT OF MP&L'S PERFORMANCE IN MAJOR PROJECT ACTIVITIES

The following are summaries of MP&L's performance in major functional areas that were identified in the Request for Proposal. Each summary is directed at a number of issues that were also identified in the RFP.

Project Preplanning

MP&L's project decisions and activities had a generally positive impact on cost and schedule and resulted in timely receipt of a Construction Permit. The key decisions/activities during this project phase included the decision to build two units at the Port Gibson site; development of the project financing strategy; and preliminary design, licensing and procurement activities.

Site selection was accomplished by Bechtel, MP&L and New Orleans Public Service. Location of the site can affect project cost and schedule three ways: poor subsurface conditions, emergency evacuation planning problems, and labor shortages due to remoteness or competition with nearby projects. None of these siting problems affected cost and schedule at GGNS. With regard to the project financing strategy, formation of Middle South Energy (MSE) appears to have been the most feasible option available to the MSU operating companies. Preliminary design and procurement were performed by Bechtel and monitored by MP&L. Grand Gulf licensing was accomplished by MP&L with extensive support from Bechtel and General Electric. The impact of these activities, if any, was positive.

MP&L's involvement in project preplanning activities, combined with the results achieved during this period, support the conclusion that the Company controlled factors impacting schedule and cost to the extent possible.

Project Management and Organization

MP&L's overall project organization and management adequately supported the evolving needs of the project and permitted Bechtel to perform its delegated roles. These factors, in themselves, were not responsible for cost escalation or schedule slippage.

MP&L's organization, policies and procedures were developed throughout the project. In addition, MP&L assigned a contingent of qualified personnel to manage the project. In those instances in which inadequacies were identified, MP&L undertook remedial action in a timely manner.

Bechtel, charged with key responsibilities throughout the project, staffed GGNS with experienced and qualified personnel. The project teams of both MP&L and Bechtel had less personnel turnover than observed on similar projects. This helped provide a high degree of continuity and had a generally positive impact on GGNS. However, the project experienced problems with turnover of some critical craft labor due to severe labor shortages throughout the United States. MP&L and Bechtel took adequate corrective actions to resolve this undesirable situation.

Planning & Control

While factors largely beyond MP&L's control resulted in continuous cost and schedule underestimation, planning of project activities and control of Grand Gulf cost, schedule and scope were adequate. In addition, the planning and control activities did not, in themselves, contribute to cost and schedule growth.

MP&L was involved in project planning and control even though Bechtel had direct responsibility for these activities during the engineering and construction phases. MP&L's involvement grew as the project progressed, with the Company assuming complete planning and control responsibility during start-up and pre-operational testing. The planning and control systems used on GGNS were contemporary in nature, and were implemented by skilled personnel. An explanation of the apparent incongruity between a contemporary planning and control system and the lack of forecasting accuracy experienced at GGNS is suggested by recent studies of cost estimation and growth on projects involving new technologies. These studies concluded that cost and schedule increases were attributable to unproven technology, plant complexity and the lack of precise project definition—all of which are common on nuclear power plant projects.

Corporate Support Functions

Despite the magnitude of the Grand Gulf project and the disruption of financial markets which occurred during its construction, MP&L's performance in financial planning and auditing did not adversely affect either project cost or schedule.

Cost and schedule increases on Grand Gulf were the result of external factors—unprecedented inflation, mounting interest rates, the TMI accident, regulations, etc.—and not of non-availability of funds due to inadequate financial planning. The average cost of funds

AN ASSESSMENT OF MP&L'S PERFORMANCE IN MAJOR PROJECT ACTIVITIES
(Continued)

used to finance Grand Gulf was not unusually high in light of the impact which events such as TMI had on financial markets. In terms of auditing MP&L ensured that adequate internal controls were in place and that items which would have a negative impact on cost were uncovered.

Licensing

While the complexity of nuclear power plant licensing grew dramatically during the 1970's and 1980's, MP&L generally executed licensing activities with proper regulatory compliance and adequate timeliness to support the Grand Gulf schedule and contain cost increases.

GGNS was the first project to receive a Limited Work Authorization, and it received a Construction Permit six months faster than the industry average. Occasional problems experienced with certain licensing documentation, i.e., the plant technical specifications, were more a reflection of increased NRC requirements than of inadequate responsiveness or non-compliance on the part of MP&L.

Engineering

While the design and engineering of Grand Gulf were performed by Bechtel, MP&L adequately directed the overall engineering effort and, along with Bechtel, controlled the cost of design changes, maintained engineering quality, responded to NRC directives and assured coordination of engineering with other project activities.

MP&L reviewed, approved and controlled the cost of design changes through involvement in the design change process and through use of written procedures. Engineering quality was maintained primarily through reviews that were part of Bechtel's Quality Engineering Program, which, in turn, was in accordance with MP&L's overall Quality Assurance Program. Engineering provided timely and adequate support to licensing in the preparation of the Preliminary and Final Safety Analysis Reports and in responding to NRC questions, concerns and requirements. In addition, MP&L and Bechtel developed formal mechanisms to promote coordination between engineering and all other project activities.

Contract Management

MP&L's selection of the three major contracts—engineering/construction, nuclear steam supply system, and turbine generator—was objective, rational and unbiased. MP&L's administration of these contracts was adequate, and cost increases in these contracts were not attributable to MP&L contract management performance.

MP&L awarded these three contracts only after a comprehensive evaluation of competing suppliers and firms, including a review of their technical abilities, experience and commercial terms. In particular, the evaluation of the engineering/construction bidders was better than normal industry practice. Further, a foreign turbine generator vendor was sought due to the backlog of orders with domestic suppliers. MP&L negotiated the most favorable contract terms generally available at the time. The contracts included performance clauses to protect MP&L's rights.

Procurement

MP&L managed the procurement function on the Grand Gulf project and became involved in procurement activities, as necessary, to enforce its contractual rights, contain costs and support the project schedule.

The bidding process, vendor selection and overall procurement practices, including subcontract management procedures, used on Grand Gulf were professional and met project schedule requirements and industry standards.

Our review of procurement activities did not reveal any instances of an inability to procure needed items or services in a reasonably timely manner. Indeed, whenever there was uncertainty about the security of supply to meet the project schedule, Bechtel advised MP&L of the potential problem and MP&L negotiated sole source commitments. In addition, procurement procedures and practices were adequate to control vendor and subcontract costs. Further, MP&L took measures to track materials and equipment and to maintain security, thus limiting the potential for losses.

AN ASSESSMENT OF MP&L'S PERFORMANCE IN MAJOR PROJECT ACTIVITIES
(Continued)

Construction Management

Bechtel's performance in management of GGNS construction and MP&L's involvement in the process were adequate. GGNS construction management practices and the manner in which MP&L/Bechtel responded to problems helped to achieve an overall construction duration shorter than that of most nuclear plants built during the same period.

While MP&L's role in construction on Grand Gulf was essentially limited to overseeing Bechtel's activities, MP&L performed this function in a satisfactory manner. For its part, Bechtel made orderly and effective changes in its organizational structure to meet the changing needs of construction operations, and assigned qualified and experienced personnel to the project. In addition, MP&L and Bechtel negotiated an effective labor agreement; implemented corrective measures to mitigate the labor shortage and turnover problems; and sought to control labor productivity through detailed planning, increased supervision, additional training and other programs. These actions, combined, had a beneficial effect on project schedule and cost.

Start-Up Management

While the start-up and pre-operations period was, without doubt, the most difficult phase of the Grand Gulf project, MP&L satisfactorily planned and managed those activities, and worked to minimize the cost and schedule impact of the factors which were beyond its control.

Start-up and pre-operational testing activities were directly planned, controlled and staffed by MP&L. The Company began planning, scheduling and staffing for start-up early in the project, and was thorough in its preparation of appropriate procedures. The lengthy overall start-up/pre-operational period, and accompanying cost increases, were due to events outside MP&L's control and not to MP&L's management or execution of start-up and pre-operational testing.

Quality Assurance

Review of the project indicated that MP&L worked from the outset to ensure the design, construction and operation of a quality plant. Implementation of this approach has enabled Grand Gulf to avoid the costly quality-related problems which have plagued many other nuclear plants.

The overall quality assurance program developed and implemented by MP&L on Grand Gulf integrated the quality programs of the NRC, Bechtel, General Electric and other vendors and contractors. MP&L and Bechtel assigned skilled personnel in sufficient numbers to adequately implement the quality program throughout the duration of the project. Also, the Grand Gulf quality program was implemented in accordance with written procedures that met the intent of NRC and industry requirements. The overall effectiveness of the quality program is evidenced by the small number and low severity of quality-related deficiencies detected by audits and inspections.

APPENDIX

NUCLEAR POWER INDUSTRY PERSPECTIVE

Figure 8a
Causes for Cost and Schedule Increase

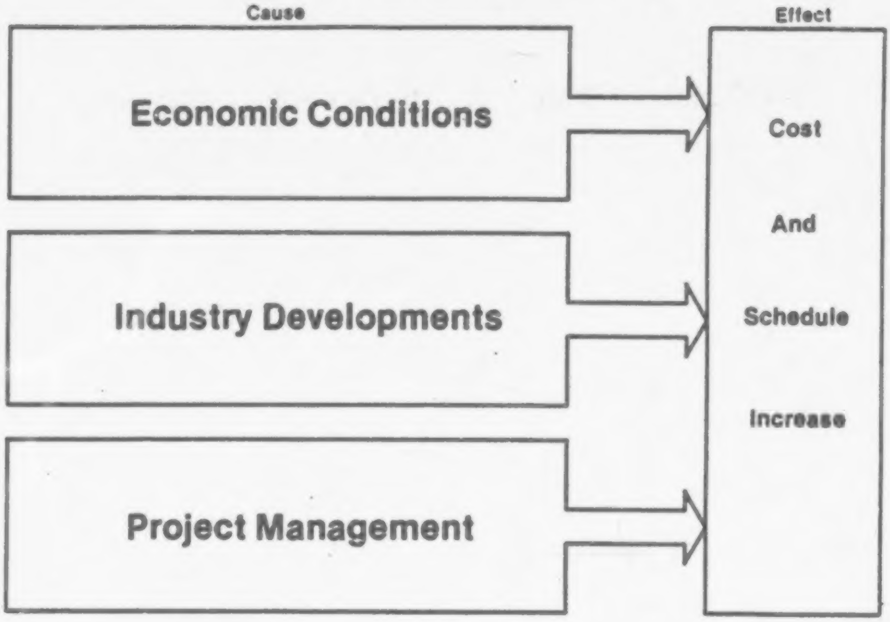

Cause
Effect
Economic Conditions
Industry Developments
Project Management
Cost
And
Schedule
Increase

Figure 8b
Cost Escalation

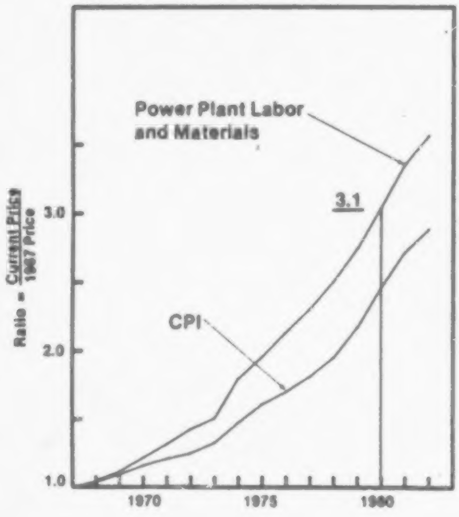
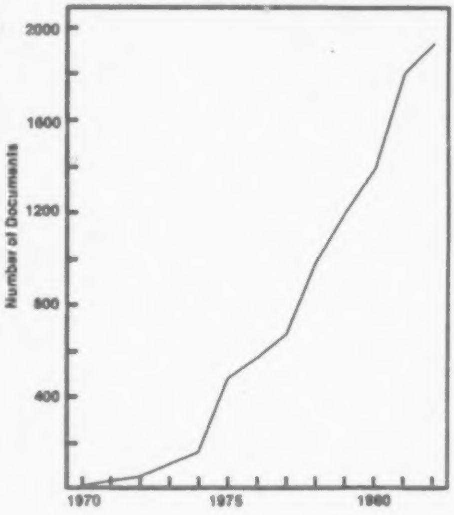


Figure 8c
Regulatory Development



CAUSES FOR COST AND SCHEDULE INCREASE

The cost of U.S. commercial nuclear power increased ten-fold from 1970 to the early 1980's. During the same period, the overall schedule to design and construct nuclear plants more than doubled. This marked increase in both cost and schedule was primarily caused by economic conditions, industry developments and project management (**Figure 8-a**).

Economic Conditions

During the 1970's, inflation reached unprecedented levels, causing the costs of construction labor, equipment and materials to rise dramatically. For example, the composite index of direct costs for electric power plants indicated that between 1967 and 1980 these costs tripled, increasing faster than the overall inflation rate (**Figure 8-b**). Inflation also caused higher interest rates which severely impacted nuclear plant costs.

Since nuclear projects were requiring greater financial commitments, utilities were forced to become more dependent on external financing, primarily the bond market. Long term interest rates on newly issued utility bonds increased steadily during the 1970's, from about 8 percent in 1970 to over 15 percent by the early 1980's.

The rapid growth of the nuclear industry in the early 1970's created a shortage of experienced engineers and other technical personnel throughout the industry, as well as shortages of construction labor in many regions of the country. These shortages also contributed to increasing plant costs.

Industry Developments

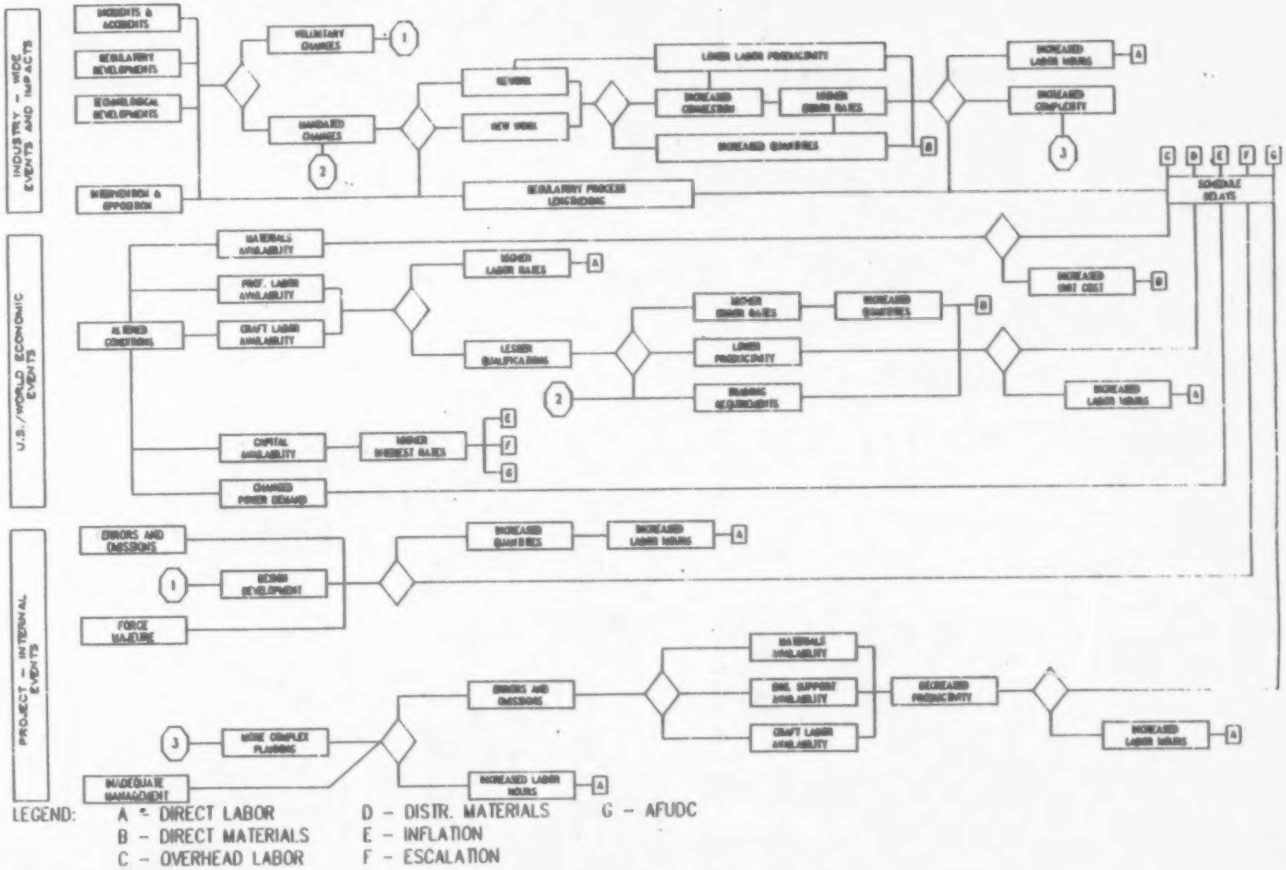
During the 1970's, the licensing and regulation of nuclear plant construction became lengthy and complex. The number of new regulations issued by the NRC and other agencies increased at a rapid pace. The sharp increases in the number of regulatory requirements was driven by the demand to meet new technological developments, the increasing focus on safety, and the need to respond to incidents and accidents (**Figure 8-c**). Similarly, there was increased development of industry codes and standards in the 1970's, often in anticipation of government regulations and in response to pressure on the industry to adopt stricter measures to assure the safety of nuclear plants.

Finally, the complexity and uniqueness of nuclear plants also increased considerably during the 1970's. Reactor manufacturers introduced larger plants with a variety of different equipment options. This, coupled with individual utility preferences, site characteristics and technological developments, produced a unique design for each plant and required special analysis and licensing.

Project Management

As the complexities and requirements to construct nuclear plants increased during the 1970's, so did the need for effective management. In general, management systems in the industry did not keep pace with the growing complexity of projects. In some cases, projects employed outdated or inadequate management systems, used inexperienced management personnel, and/or failed to delegate adequate authority and responsibility for project management. In other cases, management failed to develop project plans integrating engineering, procurement, construction and start-up activities; made incomplete and inaccurate estimates of project scope, schedule and cost; selected inappropriate contract formats; and/or failed to manage contractors and subcontractors. The combined effect of the above factors was reflected in decreased productivity, schedule delays and cost escalation.

Figure 9
Linkage Between Cost/Schedule Increases and Causes


INDUSTRY - WIDE EVENTS AND IMPACTS
INCIDENTS & ACCIDENTS
REGULATORY DEVELOPMENTS
TECHNOLOGICAL DEVELOPMENTS
INTERVENTION & OPPOSITION
VOLUNTARY CHANGES
1
MANDATED CHANGES
2
REWORK
NEW WORK
REGULATORY PROCESS LENGTHENING
LOWER LABOR PRODUCTIVITY
INCREASED CONGESTION
HIGHER ERROR RATES
INCREASED QUANTITIES
B
INCREASED LABOR HOURS
A
INCREASED COMPLEXITY
3
C
D
E
F
G
SCHEDULE DELAYS
U.S./WORLD ECONOMIC EVENTS
MATERIALS AVAILABILITY
PROF. LABOR AVAILABILITY
ALTERED CONDITIONS
CRAFT LABOR AVAILABILITY
HIGHER LABOR RATES
A
LESSER QUALIFICATIONS
INCREASED UNIT COST
B
HIGHER ERROR RATES
INCREASED QUANTITIES
B
LOWER PRODUCTIVITY
2
TRAINING REQUIREMENTS
INCREASED LABOR HOURS
A
CAPITAL AVAILABILITY
HIGHER INTEREST RATES
E
F
G
CHANGED POWER DEMAND
PROJECT - INTERNAL EVENTS
ERRORS AND OMISSIONS
1
DESIGN DEVELOPMENT
FORCE MAJEURE
INCREASED QUANTITIES
INCREASED LABOR HOURS
A
3
MORE COMPLEX PLANNING
INADEQUATE MANAGEMENT
ERRORS AND OMISSIONS
INCREASED LABOR HOURS
A
MATERIALS AVAILABILITY
ENG. SUPPORT AVAILABILITY
CRAFT LABOR AVAILABILITY
DECREASED PRODUCTIVITY
INCREASED LABOR HOURS
A
LEGEND:
A - DIRECT LABOR
B - DIRECT MATERIALS
C - OVERHEAD LABOR
D - DISTR. MATERIALS
E - INFLATION
F - ESCALATION
G - AFUDC

LINKAGE BETWEEN COST/SCHEDULE INCREASES AND CAUSES

The linkage between the previously discussed events and their impact on project scope, schedule and cost is extremely complex. Its complexity stems from the lengthy time span during which impacting events took place; the random manner in which they occurred; their interaction and compounded influence; their downstream effects and by-products; and the complexity of a nuclear plant itself. A simplified model of this mechanism is graphically depicted in **Figure 9** and outlined below.

Regulatory and Technological Developments

Industry-wide events gave rise to numerous "lessons learned", standards and regulations. Most of the new requirements were mandated; some were implemented voluntarily to minimize downstream licensing risk, or because of their positive effect on the plant life cycle cost.

Mandatory changes required rework of completed structures, systems and components; added new work to the scope of the project; and lengthened the regulatory process. On some projects, lengthening of the regulatory process was also caused by intervention of the industry's opponents.

Both rework and new work were reflected in greater quantities of materials, additional equipment and increased congestion within plants. In addition, continuous rework of the same plant components decreased labor morale and led to lower productivity. Increased congestion and lessened enthusiasm often resulted in higher error rates which, in turn, further increased quantities and project scope.

Increased quantities led to a higher direct cost of materials and higher labor hours. The labor hours were further increased by lower productivity which, in turn, resulted in greater direct labor costs. Finally, the longer regulatory process, increased quantities and lower productivity resulted in schedule delays; delays raised the cost of overhead labor and distributable materials, and exposed projects to further inflation, escalation and AFUDC.

Economic Impact

The robust growth of the power industry during the early 1970's brought about shortages in shop space and qualified labor. In accordance with the law of supply and demand, unit costs of material and labor wages increased. More importantly, lower experience levels generally led to more errors, lower productivity, higher quantities and increased labor hours; these factors combined to further heighten direct costs.

Altered economic conditions also contributed in many instances to schedule delays and related cost increases. Delays at some plants were forced by rapid industry growth; others were necessitated by the lessening demand for power. These delays and high interest rates led to further increases in time-related costs.

Project Events

Problems also existed for many utilities at the local front: errors and ommissions in engineering, procurement and construction; design development necessitated by internal and external factors; and, on some projects, force majeure. Delays and overruns caused by internal problems were derived through the same mechanism as those caused by industry-wide events.

In certain cases, cost and schedule growth were also caused by improper management. On some projects, mismanagement was a result of inadequate methods and systems, and unqualified personnel. On all nuclear plants, planning and control were made immensely complex by impacting events and changes in the economic environment.

Both of the preceding causes resulted in incomplete and often inaccurate plans and status reports. Errors in plans and reports affected the availability of materials and labor, decreased productivity, increased labor hours and, in some cases, delayed project completion dates.

Figure 10a

Documentation Requirements

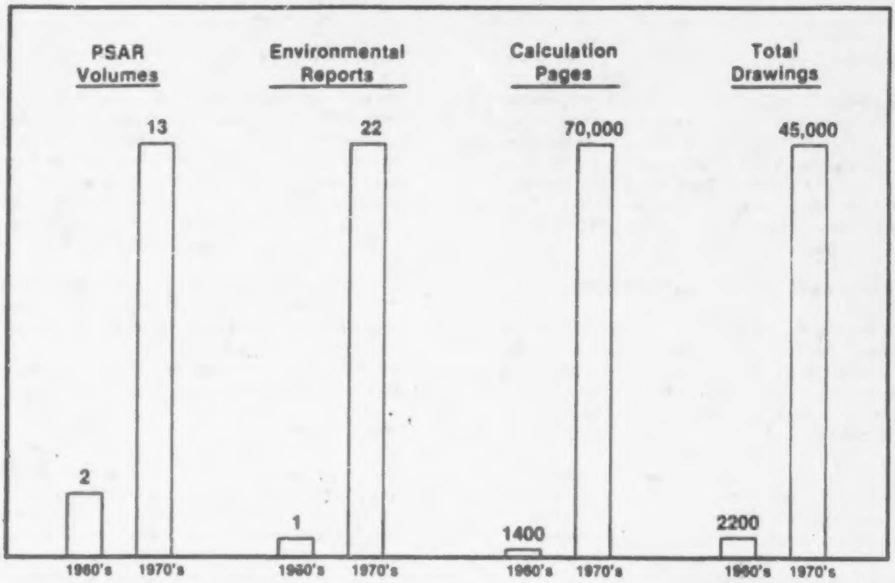


Figure 10b

Material Requirements

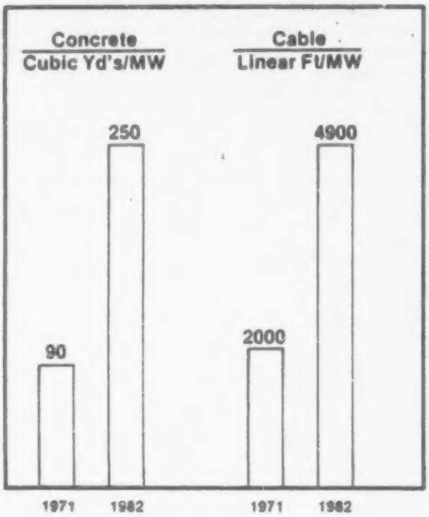
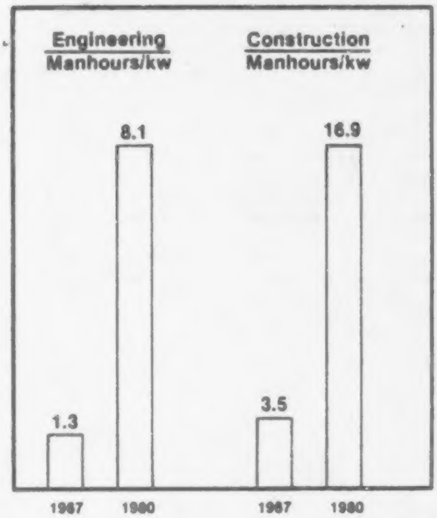


Figure 10c

Manhour Requirements



EFFECTS ON PROJECT SCOPE

A significant portion of the increase in cost and schedule of nuclear plants during the 1970's is directly related to increases in the scope of engineering, procurement, construction, and other project activities, which were driven primarily by industry-wide developments. A few of the major increases in project scope for nuclear plants are summarized below.

- The increase in regulations and standards, along with technological developments, had a profound effect on the scope of engineering and licensing activities. This is especially evident when comparing the documentation required for projects built during the 1960's with those of the 1970's (**Figure 10-a**). For example, there were approximately 70,000 pages of calculations addressing regulations and standards for plants designed in the 1970's, compared to about 1400 pages for projects engineered a decade earlier. A similar increase can be shown for the total number of required drawings.

- From a licensing standpoint, the increase in required documentation was equally dramatic, as indicated by the increase in the number of volumes of both the Preliminary Safety Analysis Report (PSAR) and the Environmental Report.

- The growth in regulations and the development of larger reactors also increased the complexity of nuclear plants during the 1970's. This is evident from the increase that has taken place in materials required on a per unit of power basis (**Figure 10-b**). For example, over two and one-half times as much concrete per megawatt was needed for plants under construction in the early 1980's, as compared to typical plants built in the early 1970's. Most of this increase was due to the seismic, radiation shielding, and missile protection requirements of new regulations. Buildings also increased in size because of new requirements for redundancy and physical separation of safety-related mechanical and electrical systems. Similar increases occurred for nearly all other materials during the 1970's.

- Technological developments and new regulations issued during the 1970's required more sophisticated and thorough engineering analyses of nuclear plants. As a result, projects became extremely manhour intensive. For example, engineering and field nonmanual services increased from 1.3 manhours per kilowatt for plants being built in the late 1960's to about 8.1 manhours per kilowatt for plants under construction in 1980 (**Figure 10-c**). The growth in regulations, plant compelxity and scope also caused a significant increase in the number of skilled laborers required to build nuclear plants. In the early 1970's, 3.5 manhours of craft labor was needed per kilowatt of installed capacity to construct plants. By 1980, plants were requiring 16.9 manhours per kilowatt.

Figure 11a
Increase in Schedule

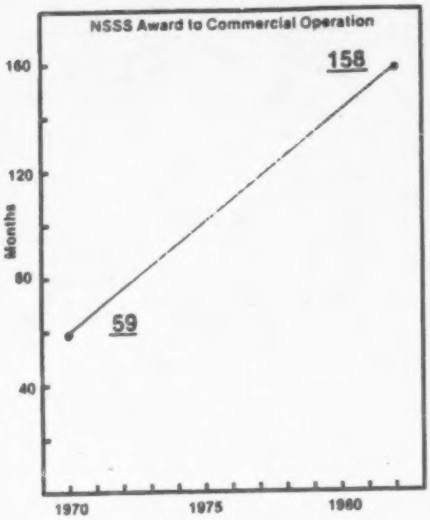


Figure 11b
Increase in Cost

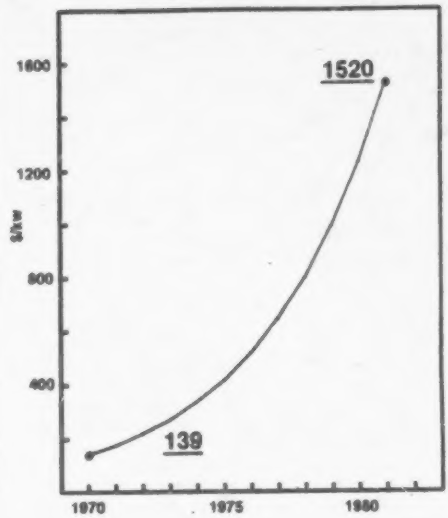
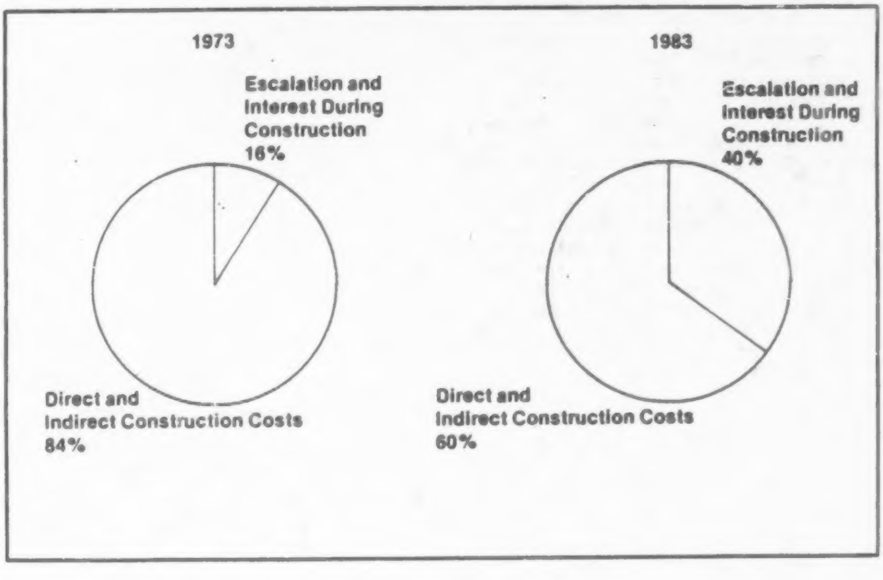


Figure 11c
Shift in Cost Composition



EFFECTS ON COST AND SCHEDULE

Economic conditions, industry deveolpments and project management had a telling effect on both the cost and schedule of nuclear projects constructed during the 1970's. The results of these effects are quantified in the following:

- Nuclear plants going into service in 1970 had a total project duration of about 59 months (**Figure 11-a**). By 1982, this duration had risen more than two and one-half times (to 158 months), representing and average annual increase of over eight months.

- The most important aspect of the increasing schedules was the rising ratio of final to original schedule. In 1970, this ratio averaged 1.2; by 1980, it had increased to 1.9. In other words, by 1980 the amount of slippage was approaching the length of the original schedule, illustrating the fact that project durations were becoming increasingly difficult to estimate.

- The increase in nuclear plant cost during the 1970's was considerably more dramatic. Plants going into operation in 1981 were costing about $1520 per kilowatt, compared to $139 per kilowatt for plants in 1970 (**Figure 11-b**).

- Even more dramatic was the increase in the ratio of final to original cost. Of 47 units that went into commercial operation between 1971 and 1982, nearly half were at least three times more expensive than originally estimated. This indicated the uncertainty and difficulty in predicting project costs, even considering that these estimates were made at the start of construction, when project scope was thought to have been fairly well defined.

- Cost escalation and interest during construction, both extremely sensitive to schedule, added dramatically to project costs and significantly changed the overall cost composition. For projects which went into operation in the early 1970's, only 16 percent of project cost was attributable to escalation and interest during construction (**Figure 11-c**). The majority of the project cost was devoted to direct and indirect construction expenses—material, equipment, labor, and professional services. However, for projects going into service in the early 1980's, interest during construction and cost escalation had increased substantially, accounting for approximately 40 percent of the total project cost.

LAW OFFICES
MITCHELL, WILLIAMS, SELIG, JACKSON & TUCKER

1000 SAVERS FEDERAL BUILDING
CAPITOL AVENUE AT SPRING STREET
LITTLE ROCK, ARKANSAS 72201
TELEPHONE 501-376-3151

H. MAURICE MITCHELL
RICHARD A. WILLIAMS
JOHN S. SELIG
JOSEPH W. GELZINE
W. CHRISTOPHER BARRIER
JERRY D. JACKSON
JIM GUY TUCKER
EUGENE G. SAYRE
BYRON FREELAND
KENT FOSTER
ALLAN GATES
PAT MORAN
W. H. L. WOODYARD, III
MICHAEL C. O'MALLEY
JOHN C. LESSEL
DOAK FOSTER
JAMES E. SMITH, JR.
JEAN D. STOCKBURGER
ANNE RITCHEY

DEBRA K. BROWN
SUSAN GUNTER
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JOYCE KINKEAD
DOUGLAS B. WARD
MARCELLA J. TAYLOR
TIMOTHY W. GROOMS
ROBERT L. THACKER
RICHARD C. JANS

OF COUNSEL
HENRY E. SPITZBERG

June 5, 1985

Mr. Cecil Alexander
Vice President,
Public Affairs
Arkansas Power & Light Company
P. O. Box 551
Little Rock, Arkansas 72203

Re: S. 1149 Ratepayer Protection Act of 1985

Dear Cecil:

You have requested our opinion as to the constitutionality of the above referenced legislation if enacted into law in substantially its present form.

A. Proposed Legislation

This proposed legislation (introduced in the Senate by Senator Dale Bumpers for himself and Senator David Pryor) would amend the Federal Power Act to permit state public service commissions to disallow, for retail rate case purposes, wholesale power costs or charges which have been approved by the Federal Energy Regulatory Commission where such costs:

(1) are applicable to the transmission or sale of electric energy between affiliated companies of a public utility holding company system; and

(2) are based upon an allocation of electric energy or costs of production of electric energy from a generating unit; and

(3) the company receiving or purchasing the electric energy is subject to the jurisdiction of a state commission which had not approved the construction of such generating unit.

Thus, this legislation would give the state commissions the authority to determine whether a utility may flow through to its retail customers any costs incurred under rates approved by the FERC, involving purchases of electricity between utility companies within the same public utility holding company system, where the state commission has not approved the construction of the generating unit upon which the rates are based.

The proposed legislation would apply to any rates or charges fixed or permitted to become effective by the FERC after May 1, 1985.

Senator Bumpers stated that the specific purpose of his bill is to permit the Arkansas Public Service Commission to refuse to pass through any costs incurred by Arkansas Power & Light Company to its retail customers if the FERC allocates to AP&L any of the costs associated with the Grand Gulf or Waterford 3 nuclear units in Mississippi and Louisiana.

If enacted in substantially its present form, the bill would certainly appear to grant that authority and our analysis assumes its exercise.

B. Status of Current Law

Under the Federal Power Act, the FERC has the sole and exclusive authority to regulate the rates for wholesale sales of electricity in interstate commerce. FPC v. Southern California Edison, 376 U.S. 205 (1964). Since the FERC has sole and exclusive jurisdiction over such wholesale sales in interstate commerce, the authority of the states in this area has been preempted by Congress under the supremacy clause of the Constitution of the United States.

Due to the federal preemption of the power of the states in this area, the so-called "filed rate doctrine" has precluded inquiry by state regulatory authorities into the reasonableness of the rates and charges approved by the FERC. Montana-Dakota Utilities Co. v. Northwestern Public Service Company, 341 U.S. 246 (1951). Thus, when setting the retail rates of utilities which have incurred costs under effective FERC rate schedules, the courts have consistently held that the state commissions may not question the reasonableness of such costs. Narragansett Electric Company v. Burke, 119 R.I. 559, 381 A.2d 1358, cert. den. 435 N.S. 972 (1977); Eastern Edison Company v. Department of Public Utilities, 388 Mass. 292, 446 N.E.2d 684 (1983); Public Service Co. of Colorado v. Public Utilities Commission of Colorado, 644 P.2d 933 (1982). As stated by the North Dakota Supreme Court in Northern States Power Co. v. Hagen, 314 N.W.2d 32 (1981):

> The PSC has no jurisdiction over interstate wholesale rates and we believe it would undermine the supremacy clause and the preemption doctrine for the PSC to indirectly assert jurisdiction over the wholesale rates by investigating the reasonableness of underlying costs in a proceeding involving retail rates. Furthermore, we believe it would frustrate the purpose of Congress in establishing reasonable wholesale rates if the reasonableness of these rates as an operating expense were inquired into by and made subject to the North Dakota PSC in establishing reasonable retail rates. If this were permitted the efforts of FERC would be reversible by the PSC, which was not contemplated by the congressional act.

The proposed legislation would attempt to reverse the effect of these judicial decisions with respect to charges incurred under FERC effective rates for power generated by a power plant which has not been certificated by the state commission.

C. Constitutional Objections To The Proposed Legislation

1. If enacted into law, the proposed legislation would deprive Arkansas Power & Light Company of its right to

recover through its retail rates in Arkansas and Missouri any costs associated with the Grand Gulf or Waterford 3 nuclear plants which are allocated to it by the FERC. The proposed legislation does not attempt to alter the authority of the FERC to require AP&L to incur a share of the responsibility for the cost of Grand Gulf and Waterford 3. As a result, if the Act is amended as proposed, the Federal Power Act could operate so as to permit the FERC to impose costs upon AP&L but, at the same time, to deny AP&L the ability to recover those costs through its retail rates. As a result, AP&L would necessarily suffer an unconstitutional confiscation of its property without just compensation in violation of the Fifth and Fourteenth Amendments to the Constitution of the United States.

2. It could further be argued that the proposed legislation would also violate the Contract Clause of the Constitution of the United States which prohibits an impairment of contractual obligations. It is obvious that if Arkansas Power & Light Company is not able to recover any costs associated with Grand Gulf which are allocated to it by the FERC, it will not be financially able to pay for such power. Thus, the seller's rights under such contracts for the sale of power, or the means of enforcing such rights, would be substantially impaired.

Article I, § 10, Clause 1 of the United States Constitution forbids the states from passing any law that will impair the obligation of contracts. We are dealing with proposed federal legislation which presumes to specifically empower a state to act retroactively to impair the obligations of the Company's existing contracts, which were legally entered into. Hence, S. 1149 presumes to grant the State of Arkansas the right to commit an unconstitutional act, a power Congress obviously does not have.

3. Serious constitutional questions are also presented because of the penalty which would be imposed upon utility companies for past action or inaction which was not unlawful under prior law. This unconstitutional result would occur because the proposed legislation would penalize AP&L (by denying it the ability to recover Grand Gulf or Waterford 3 costs imposed upon it by FERC) because the Arkansas Public Service Commission and the Missouri Public Service Commission did not approve the construction of these units.

The construction of Grand Gulf and Waterford 3 did not require the approval of either the Arkansas Commission or the Missouri Commission at the time construction was begun or at any time during the construction of these units. Not only was Commission approval not required, there was no statutory authorization for the Commissions of Missouri or Arkansas to grant certificates or approvals for the construction of power plants located outside of their respective states.

Thus, it is likely that such approvals would have been impossible to secure, even if requested, since there was no statutory mechanism available to the Company to secure such approvals. State commissions, as a rule, will not issue advisory opinions where there is no statutory authorization to grant such approvals.

Since the construction of these units is now complete, it would be impossible for AP&L to comply with these requirements retroactively. Furthermore, since there was no legal requirement to secure the approval of the construction of these units from either the Arkansas or Missouri Commissions under state or federal laws, this legislation would cause the Company to suffer a new liability resulting from past completed acts that were legally proper at the time.

Thus, the proposed legislation would clearly have a retroactive or retrospective effect if applied to deprive AP&L of the right to recover any costs imposed upon it by the FERC which are associated with the construction of either the Grand Gulf or Waterford 3 nuclear units.

D. Constitutionality of Retrospective Legislation

A retrospective law is one that relates back to a previous transaction and gives it some different legal effect from that which it had under the law when it occurred, and, in the sense in which it is constitutionally objectionable, is one that impairs vested rights acquired under existing laws, or creates new obligations, imposes a new duty or attaches a new disability with respect to past transactions.

Although not favored, retrospective statutes are not per se unconstitutional. Stephens v. Cherokee Nation, 174 U.S. 445, 477-78, 19 S. Ct. 722, 734, 43 L. Ed. 1041 (1899); Travelers Insurance Co. v. Marshall, 634 F.2d 843, 846 (1981). However, the retrospective aspects of legislation, as well as the prospective aspects, must meet the test of due process, and the justifications for the latter may not suffice for the former. Usery v. Turner Elkhorn Mining Co., 428 U.S. 1, 49 L. Ed. 2d 752, 96 S. Ct. 2882 (1976).

In Usery, the United States Supreme Court enunciated the basic test for evaluating the constitutionality of retrospective legislation. The Court stated

> It is by now well established that legislative Acts adjusting the burdens and benefits of economic life come to the Court with a presumption of constitutionality, and that the burden is on one complaining of a due process violation to establish that the legislature has acted in an arbitrary and irrational way....[O]ur cases are clear that legislation readjusting rights and burdens is not unlawful solely because it upsets otherwise settled expectations...even though the effect of the legislation is to impose a new duty or liability based on past acts.
>
> It does not follow, however, that what Congress can legislate prospectively it can legislate retrospectively. The retrospective aspects of legislation, as well as the prospective aspects, must meet the test of due process, and the justifications for the latter may not suffice for the former.

Id. at 15-17.

The Supreme Court also stated that the due process analysis of a retrospective imposition of liability must take into account whether the complaining party knew or could have anticipated the subject of the legislation and must also consider whether the complaining party's conduct prior to the legislation "may have been taken in reliance upon the current state of the law, which imposed no liability on them..." for that conduct. Id. at 17.

The Supreme Court stated, however, that it would hesitate to approve the retrospective imposition of liability on any theory of deterrence or blameworthiness. 428 U.S. at 16.

Instead, it appears that the proper standard is not whether there is any retrospective impact that would have changed settled expectations but whether the effects are "wholly unexpected, harsh or oppressive" and in each case it is necessary to consider the nature of the legislation and the circumstances in which it is laid before it can be said that its retrospective application is so harsh and oppressive as to transgress the constitutional limitation. S & M Paving v. Construction Laborers Pension Trust, 539 F. Supp. 867 (1982).

The courts consider four factors in evaluating the constitutionality of retrospective legislation. These four factors are:

1) the reliance interests of the parties affected;

2) whether the private interest which is impaired is in an area previously subject to regulatory control;

3) the equities of imposing the legislative burdens; and

4) the inclusion of statutory provisions designed to limit and moderate the impact of the burden.

Nachman Corp. v. Pension Benefit Guaranty Corp., 592 F.2d 947, 960 (7th Cir. 1979), aff'd on other grounds, 446 U.S. 359 (1980).

Utilizing this four-prong test to evaluate the constitutionality of S. 1149, we are of the opinion that this legislation could not constitutionally be applied to restrict AP&L's ability to recover costs associated with Grand Gulf or Waterford 3.

As to the first factor of reliance, it is appropriate to examine the extent to which the parties relied on the continuation of existing laws and to examine the types of interest involved in this reliance. As stated by the United States Supreme Court in Welsh v. Henry, 305 U.S. 134, 59 S. Ct. 121, 83 L. Ed. 87 (1938), "...in measuring reliance of a party, one must look at what that party would have done if he had known that the legislation was coming."

Furthermore, no one should be held reasonably to anticipate a given type of Congressional action on any subject and there is no authority that imposes on anyone the burden of predicting Congressional action. Shelter Framing Corp. v. Carpenters Pension Trust, 543 F. Supp. 1234 at 1249. Evidence that the party would have altered or changed his past conduct is convincing evidence of reliance on existing law, lack of knowledge of future changes, and unfairness in retroactive application of the legislation in issue.

It would appear that AP&L could easily demonstrate that it would have changed its conduct and would have taken one of several alternative actions to avoid this catastrophic liability from being imposed had it known this legislative penalty would be imposed.

The second prong of the four-part test, that being whether or not this legislation is in an area previously subject to regulation, has been viewed as "really just another facet of reliance. It goes to the reasonable expectations of the party upon whom the burden of the retroactive legislation falls." Shelter Framing at 1251.

In Shelter Framing, the court distinguished between legislative changes that are an "anticipated and normal risk taken by those who do business in a regulated field" and legislation that imposes "much heavier and more drastic burdens than had been imposed by the prior law." Id. The court stated that "for retroactive legislation in a previously regulated area to be valid, the new and more burdensome legislation must be closely akin in type and scope to the prior regulation." As stated by the court:

> Our Plaintiffs, although they were in a field that the government had already regulated somewhat, could not reasonably have foreseen a change of this scope and nature in the regulation of the field, especially when applied on a totally retroactive basis.
>
> The essence of the concept of reliance...is that a party should be able confidently to anticipate the consequences of a transaction, knowing what the law provides when he concludes that transaction. If he is in a regulated field, he can anticipate some clarification and modification of the scope of regulation, but cannot foresee change of a most drastic type, especially when applied to a transaction already completed before the new legislation is enacted.

Id. at 1251-52.

In our opinion, a similar conclusion would be applicable to Arkansas Power & Light Company in the context of S. 1149.

As to the third and fourth prongs of the Nachman test, those of equity and whether or not the statute includes any features which would "soften" or "mitigate" the burden, the Shelter court looked to the severity of the cost burden imposed on the plaintiff. The court used the words "very disproportionate," "overly drastic," and "harsh and severe" to describe a burden that involved a large sum of money. The key to the definition of severity as well as the balancing test of equities was clearly the "total amount of the liability." Id. at 1254.

The Fifth Circuit has also focused on the financial aspect of a plaintiff's burden when making a due process evaluation of retrospective legislation. In Travelers Ins. Co. v. Marshall, 634 F.2d 843 (1981), the court used a balancing test to evaluate the rationality of the economic legislation at issue. It contrasted the private burden complained of by the plaintiffs with the public benefit of the new legislation. The test of unconstitutionality which the petitioners had to prove was that the legislation was "irrational or manifestly unjust" and "so egregiously unfair as to be a deprivation of due process." Id. at 849.

Inasmuch as the penalty imposed by S. 1149 upon AP&L would result in the underrecovery of literally billions of dollars imposed upon the Company by action of the FERC, we believe that there is no question that the Company would suffer an overly drastic, harsh and severe penalty "which is so egregiously unfair as to be a deprivation of due process." Furthermore, there is absolutely nothing in the proposed legislation which would offer the Company any opportunity to mitigate or soften the burden imposed.

Thus, we believe that the equities in this situation are in the Company's favor inasmuch as the Company has complied with all legal requirements with respect to the construction of these units.

Conclusion

Applying the principles noted above to the situation which would confront the Company, it is our opinion that the proposed legislation could not be retrospectively applied to deprive Arkansas Power & Light Company of its right to recover any costs associated with the Grand Gulf or Waterford 3 nuclear units without violating the Company's rights under the Due Process Clause of the Fifth Amendment to the Constitution of the United States. Further, such a deprivation would constitute confiscation of the Company's property without just compensation, in violation of the Fifth and Fourteenth Amendments, and would authorize state action to impair contracts, in violation of Article I, § 10, Clause 1 of the Constitution of the United States.

Hence, it is our opinion that the proposed legislation would be found to be unconstitutional, both in form and in its intended effects.

Very truly yours,

MITCHELL, WILLIAMS, SELIG,
JACKSON & TUCKER

By Jerry D. Jackson
Jerry D. Jackson

JDJ:nc

The CHAIRMAN. Mr. Brown.

STATEMENT OF EDWARD A. BROWN, CHAIRMAN AND CHIEF EXECUTIVE OFFICER, NEW HAMPSHIRE YANKEE ELECTRIC CORP., AND CHAIRMAN, YANKEE ATOMIC ELECTRIC CO., DIVISIONS OF PUBLIC SERVICE CO. OF NEW HAMPSHIRE

Mr. BROWN. Thank you.

My name is Edward Brown and I am chairman and chief executive officer of New Hampshire Yankee Electric Corp., and I am also chairman of Yankee Atomic Electric Co., which is located in Massachusetts.

New Hampshire Yankee, now operating as a division of Public Service of New Hampshire, is the managing agent for the joint owners in the construction and operation of the Seabrook project. The Seabrook project is a 2-unit nuclear powerplant located in Seabrook, NH. Unit 1 is about 90 percent complete and is scheduled to be in commercial operation before the end of next year.

To date, $3.4 billion has been invested in unit 1, consisting of $2.3 billion cash and $1.1 billion of interest. Unit 2 is about 25 percent complete. At the present time no work is being performed on unit 2 except for that work which is necessary to preserve and protect the asset.

I want to thank the Senate Committee on Energy for the opportunity to speak today. I will briefly review the regulatory processes, both State and Federal, for licensing powerplants which have been put in place over the last 15 to 20 years. And I will use the Seabrook project, that's the last project in New England to go through this process, as an example of the regulatory labyrinth our country has established. In this appearance, I will express opinions about the regulatory process, not the content or the intent of the regulations themselves.

There's an old New England story about a tourist who asks a farmer how to get to a certain town. The farmer replied that: "You can't get there from here." Any utility faced with the need to build a new base load generating plant, either coal or nuclear, must look at the licensing and regulatory maze ahead and feel like that tourist, because it's almost impossible to get there from here.

Here I have a roll of red tape listing entries of major licensing and regulatory events in Seabrook's history. In my review of these events, it's not my intent to focus on any single agency, but it is an attempt to review a system that just doesn't work.

The first entry on this roll is February 1, 1972, when an application was filed before the State Site Evaluation Committee for a certificate of site and facility.

As we get into it, at 2 feet, August 2, 1974, an application was filed with the Environmental Protection Agency for review and approval of the plant ocean water cooling system.

At about 5 feet, on March 19, 1975, the EPA released its determinations approving that ocean water cooling system, with conditions relating to design and location of the intake structures.

At 7 feet, in mid-1976 the construction permit was issued by the Nuclear Regulatory Commission, but there still was no final decision on the cooling system.

At 9 feet, we're near the end of 1976 and EPA revoked its prior determination.

On April 7, 1977, the NRC suspended the construction permit. The permit was reinstated at 12 feet, on July 26, 1977, after EPA reversed itself again.

At 15 feet, on January 7, 1978, the NRC affirmed the Appeal Board's July 1977 reinstatement of the construction permit and the NRC stated that the history of the Seabrook proceedings demonstrated a "serious failure of governmental process to resolve central issues in a timely and coordinated way."

Unfortunately, the story doesn't end there. Three months later, on April 28, 1978, the Appeals Board reversed the Licensing Board's decision and remanded the matter for further proceedings. Later, the construction permits were two more times suspended and reinstated on the issue of the cooling water system.

Time doesn't permit us to go through the remainder of this roll, but I must tell you that the plant cooling system continues as an issue today. Hearings were held by the EPA in April of 1985 and as of today, 11 years after the first application, we still do not have the last approval on that cooling system, the water discharge permit. However, we do expect that that permit will be issued within a few weeks.

The CHAIRMAN. Within a few weeks or a few feet? [Laughter.]

Mr. BROWN. However, there are still other issues to be resolved, hearings to be held, licenses to be obtained—all with the potential for appeals and litigation by intervenors.

The permitting and licensing process for Seabrook has been ongoing for a period of 13 years, and we're not through yet. Seabrook Project licensing has involved 22 Federal agencies, 25 State agencies, and at least 30 local or regional agencies.

To date, the Seabrook project has been involved in more than 700 days of hearings. That's a total of 3 working years. To support these hearings, the project has submitted required documentation of more than 500 feet of paper. That's a paper tower taller than the 50-story John Hancock Tower in Boston.

In the last 15 years, Congress has enacted a variety of laws which have added to licensing requirements and potential for delays. Just to name a few: NEPA, environmental policy; NCAA, clean air; FWPCA, water pollution control; RCRA, resource recovery and conservation; CZMA, coastal zone management. And the list goes on and on: ESA, OSHA, FEMA, CERCLA, TSCA, and HMTA, all of which we have to deal with.

A number of observations can be made on the development of regulatory process over the last 15 years. Each of these acts individually obviously addressed a need as seen by Congress. Each required people to administer it and rules and regulations to be promulgated under it.

In addition, each State, with its own cast of participants, has established laws and programs under the aegis of many of these Federal acts. This has resulted in duplication, conflicts, overlapping jurisdictions, and, not rarely, in turf battles.

Agencies have promulgated additional regulations under existing laws. For example, in the period 1972 to 1982 the NRC introduced 1,018 major new regulatory requirements according to this analysis by Ebasco for Florida Power & Light. And I'd like to add this to the record if I may, Mr. Chairman, 211 of those regulations were introduced in 1978 alone.

The CHAIRMAN. We will place that document in the committee file.

Mr. BROWN. Thank you.

The CHAIRMAN. Thank you.

Mr. BROWN. Finally, intervenors have a greater opportunity at every step of every regulatory process for delay and appeal, and the courts have shown a greater propensity to become involved in this regulatory process.

All of these factors have contributed to a process for licensing powerplants that's a patchwork quilt nightmare for the applicants and a sitting duck shooting gallery for the intervenors. We have in place a regulatory process of overlapping jurisdictions, often contradictory procedures, and systems that simply don't do what they were intended to do.

Is it any wonder, when you heard the testimony this morning, that utilities are reluctant to initiate the planning and the licensing process for any nuclear plant? Can a reasonable manager be expected to risk customer and shareholder money on a project that can take 12 to 15 years, cost billions of dollars, and have no degree of certainty that the project will receive regulatory approval at the end?

The answer to these questions is obviously no. But what can be done? The process of regulating, licensing, and permitting must be overhauled, with these goals in mind:

Eliminate the jurisdictional disputes between agencies;

Impose binding timeframes on agencies requiring them to act within predictable time periods and eliminate the open-ended processes;

Three, build some certainty into the process so that those applicants already involved in a process are not faced with a myriad of rule changes along the way;

Four, streamline the process and reduce the overall timeframe to get through it;

Five, build some glue into the system so that an approval, when it's issued and with reasonable time for due process appeal, will stick under most circumstances and not be subject to later change, modification, withdrawal, or endless appeals.

New generating capacity will be needed in New England and the remainder of the United States. The questions Congress should address are: Where will this needed capacity come from? And who is going to take the risks to build, with all the uncertainties inherent in our existing regulatory maze? What can Congress do to make the regulatory process more predictable and rational, so that utility companies will be able to enter into the process of building what will be needed?

Now, my testimony has dwelt on the Seabrook nuclear project, but the thrust of my remarks is intended to cover all baseload generation. In my previous position I was involved in the licensing of a reconversion to coal of a plant that was designed to burn coal, built to burn coal, and in fact did burn coal before converting to oil. The licensing process to convert back to coal, which was started immediately after the first oil embargo, required over 5 years, and that's longer than it took to wage and win World War II.

The State and Federal regulatory process must be made rational so that the utility industry can support the energy needs of the country, assist in keeping us energy independent from foreign imports, and to keep the cost to consumers at the lowest possible level.

[The prepared statement of Mr. Brown follows:]

Appearance of Edward A. Brown

Before The

United States Senate Committee On Energy and Resources

Washington, D.C.

July 23, 1985

My name is Edward A. Brown. I am Chairman and Chief Executive Officer of New Hampshire Yankee Electric Corporation and am Chairman of Yankee Atomic Electric Company, which is located in Massachusetts.

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I want to thank the Senate Committee On Energy for the opportunity to speak today. I will briefly review the regulatory processes, both state and federal, for licensing power plants which have been put in place over the past 15 to 20 years. I will use the Seabrook Project, the last project in New England to go through this process, as an example of the regulatory labyrinth our country has established. In this appearance, I will express opinions about the regulatory process, not the content or intent of the regulations themselves.

There is an old New England story about a tourist who asked a farmer how to get to a certain town. The farmer replied that "you can't get there from here".

Any utility, faced with the need to build a new base load generating plant (either coal-fired or nuclear) must look at the licensing and permitting maze ahead and feel like the tourist because it is almost impossible to "get there from here".

Here I have a roll of red tape listing entries of major licensing and regulatory events in Seabrook's history. In my review of these events, it is not my intent to focus on any single agency -- it is an attempt to review a system that does not work. The first entry is February 1, 1972 when an application was filed before the state Site Evaluation Committee for a Certificate of Site and Facility. (Unroll) At two feet, on August 2, 1974 an application was filed with the Environmental Protection Agency for review and approval of the plant ocean water cooling system. (Unroll) At about 5 feet, on March 19, 1975, the EPA released its determinations approving the ocean water cooling system with conditions relating to design and location of intake structures. (Unroll) At 7 feet, in mid-1976, the Construction Permit is issued by the Nuclear Regulatory Commission but there is no final decision on the cooling system. (Unroll) At 9 feet, we are near the end of 1976 and EPA revokes its prior determinations. On April 7, 1977 the NRC suspends the construction permit. The permit was reinstated at 12 feet, on July 26, 1977 after EPA reversed its earlier decision. (Unroll) At 15 feet, on January 7, 1978, the NRC affirmed the Appeal Board's July 1977 reinstatement of the construction permits. The

NRC stated that the history of the Seabrook proceedings demonstrated a "serious failure of governmental process to resolve central issues in a timely and coordinated way".

But story does not end there. Three months later, on April 28, 1978, the Appeals Board reversed the Licensing Board's decision and remanded the matter for further proceedings. Later, the construction permits were twice suspended and reinstated on the issue of the cooling water system.

Time does not permit us to go through the remainder of the roll, but I must tell you that the plant cooling system continues as an issue. Hearings were held by the EPA in April 1985 and, as of today, eleven years after the first application, we still do not have the last approval on the cooling system, the water discharge permit. There are still other issues to be reviewed, hearings to be held, licenses to be obtained -- all with the potential for appeals and litigation by intervenors.

The permitting and licensing process for Seabrook has been on-going for a period of 13 years and we are not through yet. Seabrook project licensing has involved 22 federal agencies, 25 state agencies and at least 30 local agencies. To date, Seabrook project has been involved in more than 700 days of state and federal hearings -- a total of 3 working years. To support these hearings, the project has submitted required documentation of more than 500 feet of paper, a paper tower taller than the 50 story John Hancock Tower in Boston.

In the last 15 years, the Congress has enacted a variety of laws which have added to licensing requirements (and exposure to delays).

NEPA -- Environmental Policy

NCAA -- Clean Air

FWPCA -- Water Pollution Control

RCRA -- Resource Conservation & Recovery

CZMA -- Coastal Zone Management

ESA -- Endangered Species

OSHA -- Occupational Safety & Health

FEMA -- Emergency Management

CERCLA -- Environment Conservation Liability

TSCA -- Toxic Substances Control

HMTA -- Hazardous Materials Transportation

A number of observations can be made on the development of regulatory process over the last 15 years:

1. Each of these acts, individually, obviously addressed a need as seen by Congress. Each required people to administer it and rules and regulations to be promulgated under it.

2. In addition, each state ~~with~~ their own cast of participants has established laws and programs under the aegis of many of these federal acts. This has resulted in duplication, conflicts, overlapping jurisdictions and, not rarely, in "turf battles".

3. Agencies have promulgated additional regulations under existing laws. For example, in the period 1972 to 1982 the NRC introduced 1,018 major new regulatory requirements according to this analysis by Ebasco for Florida Power and Light. 211 were introduced in 1978 alone.

4. Finally, intervenors have a greater opportunity at every step of every regulatory process for delay and appeal -- and the courts have had a greater propensity to become involved in the regulatory process.

All of these factors have contributed to a process for licensing power plants that is a patchwork quilt nightmare for the applicants and a sitting duck shooting gallery for the intervenors. We have in place a regulatory process of overlapping jurisdictions, often contradictory procedures and systems that simply don't do what they are intended to do.

Is it any wonder then that utilities are reluctant to initiate the planning and licensing process for any new plant?

Can a reasonable manager be expected to risk customer and shareholder money on a project that can take 12 to 15 years, cost billions of dollars and have no degree of certainty that the project will receive regulatory approval at the end?

The answer to these questions is obviously "no". But, what can be done? The process of regulating, licensing and permitting must be overhauled with these goals in mind:

1. Eliminate the "jurisdictional disputes" between agencies.

2. Impose binding time frames on agencies requiring them to act within predictable time periods -- eliminate open ended processes.

3. Build some certainty into the process so that those applicants already involved in a process are not faced with a myriad of rule changes along the way.

4. Streamline the process and reduce the overall time frame to get through.
5. Build some "glue" into the system so that an approval, when issued and with reasonable time for due process appeal, will stick under most circumstances and not be subject to later change, modification, withdrawal or endless appeals.

New generating capacity will be needed in New England and the remainder of the United States. The questions Congress should address are -- where will this needed capacity come from? Who is going to take the risks to build with all the uncertainties inherent in our existing regulatory maze? What can the Congress do to make the regulatory process more predictable and rational so that utility companies will be able to enter into the process of building what will be needed?

My testimony has dwelt on the Seabrook nuclear project, but the thrust of my remarks is intended to cover all base load electric generation. In my previous position I was involved in the licensing of a reconversion to coal of a plant that was designed to burn coal, built to burn coal, and in fact originally burned coal before converting to oil. The licensing process tq convert back to coal, which was started immediately after the first oil embargo, required over 5 years -- longer than it took to wage and win World War II.

The state and federal regulatory process must be made rational so that the utility industry can support the energy needs of this country, assist in keeping us energy independent from foreign imports and keep the cost to consumers at the lowest possible level.

The CHAIRMAN. Thank you very much. We appreciate your testimony.

Let me turn first to Senator Bumpers.

Senator BUMPERS. Mr. Brown, with all due respect to you, my questions will all be directed at Mr. Lewis, because he and I have a big problem in Arkansas.

Mr. Lewis, let me just go through the chronology. I have read your statement, and let me go through the chronology of how Grand Gulf came into existence, to make sure that we agree on most of it. No. 1, Grand Gulf was originally conceived to supply power for Mississippi Power & Light, which at that time had a shortage of power, is that correct?

Mr. LEWIS. Not entirely, Senator Bumpers. A unit the size of Grand Gulf, 1,250 megawatts, would have been totally out of line for a company the size of Mississippi Power & Light Co. by itself. So it was planned through the operating committee, which is the top technical committee of the Middle South system.

The whole system was found to need additional capacity. Mississippi did need additional capacity, and it was decided that they would build that first unit at the Grand Gulf site. But it was on the basis that it would serve others than Mississippi Power & Light Co.

Senator BUMPERS. Well, based on your projections at that time, was it your projection that you were going to need all of this power, Grand Gulf One, Two, Waterford, and so on?

Mr. LEWIS. Yes, sir.

Senator BUMPERS. Now, if that were the case, why did you not form the subsidiary, Middle South Energy, Inc., at that time, rather than going through a site hearing with the Mississippi Public Service Commission with Mississippi Power & Light Co. as the applicant?

You knew Mississippi Power & Light couldn't finance it, did you not, at that time?

Mr. LEWIS. Senator, as I said in the statement, read the printed statement there, two units were planned on the system. One was to be the unit at the Grand Gulf site, which Mississippi Power & Light Co. was going to build. The other was planned for a site in the vicinity of New Orleans. New Orleans Public Service, the smallest company in our system, was going to develop that one.

Over the course of time, as further investigations were made it became clear that to build at the site in the New Orleans area, principally because of soil conditions there, would cost about 25 percent more, and it was the decision of the operating committee, affirmed by the chief executive officers of the companies in the system, that since the units were duplicate units, that it would be wise to put them both at the Grand Gulf site.

That was the period when the fact that you had to find another financing vehicle became very clear to everyone.

Senator BUMPERS. And so that's when you decided to form this subsidiary, Middle South Energy, Inc.?

Mr. LEWIS. Yes, sir.

Senator BUMPERS. A wholly owned subsidiary of Middle South Utilities?

Mr. LEWIS. Yes, sir.

Senator BUMPERS. And all the operating companies—Louisiana Power & Light, Mississippi Power & Light, Arkansas Power & Light, and New Orleans Public Service—are also all wholly owned subsidiaries of Middle South System?

Mr. LEWIS. That's correct, yes, sir.

Senator BUMPERS. Now, Mr. Lewis——

Mr. LEWIS. We're required, by the way, Senator, under the Holding Company Act to have all of the stock. At one time New Orleans Public Service had a small minority interest outstanding, and we were compelled to acquire that minority interest.

Under the Holding Company Act, you have to have the full ownership. They call it a sterile interest, I believe, or some such wording, if there's a minority interest that could not protect itself. So we are required by law to have 100 percent ownership.

Senator BUMPERS. But when Middle South Utilities formed Middle South Energy, Inc., and then turned around and signed the contract with Mississippi Power & Light to construct and operate this plant, I mean, this is just like a bunch of people getting together and kind of shaking hands with themselves and saying we've got a deal, isn't it?

Mr. LEWIS. Well, there was a deal made, yes, sir. Everybody agreed to it.

Senator BUMPERS. But it was all in-house, same people—Middle South Energy, Middle South Utilities—all the same people.

Mr. LEWIS. Well, all I can tell you, Senator, is that in our system each of the operating companies has a chief executive officer who is in fact a chief executive officer. He has a board of directors made up of leading people. And you know the people on the AP&L board, and they are indeed outstanding people.

Senator BUMPERS. They've done a good job of providing for our needs in Arkansas.

Mr. LEWIS. They're outstanding people, Senator, and they are an independent board.

These decisions were made by the chief executive officers on the basis of recommendations from the appropriate technical people in the system, and we looked at a number of different possibilities for financing this plant, and the best of the alternatives was the one we came up with in our opinion.

And there's some testimony on that that's just been filed in the current rate case in Arkansas, Mr. Barr of Morgan Stanley looking back at the situation, and he concludes that the way we decided to do it was the only way that the plant could in fact have been financed during the period that it was under construction.

Senator BUMPERS. Well, why did you not just allow each one of the subsidiaries then—instead of saying that we will buy power from Middle South Energy, Inc., why didn't you allow each company to say, we will pay for a share of the plant, which would have given the individual public service commissions of the various States some say-so over this whole thing?

Mr. LEWIS. Well——

Senator BUMPERS. Mr. Lewis, you've been through this many times, and I hate to repeat it, but the record here doesn't show it. The thing that the people in my State are so agitated and frustrated and upset about is the way Middle South Utilities went through what I thought was a subterfuge to avoid public service commission input in all of the States, not only Arkansas but especially Arkansas.

This whole thing took place with absolutely not so much as a by-your-leave from the Arkansas Public Service Commission and therefore from the Arkansas ratepayers. Why? Was that done to avoid State jurisdiction, this idea that we buy the power, and not a percentage of the plant, because that way you get to go to FERC and not to the individual State public service commissions?

Mr. LEWIS. My answer, sir, is a categorical no.

Senator BUMPERS. But that is the result, is it not?

Mr. LEWIS. It happens that the law since about 1935 has been that sales of electricity at wholesale in interstate commerce is subject to regulation by the Federal Power Commission, now the Federal Energy Regulatory Commission. That's been the law since the 1930's.

Senator BUMPERS. Mr. Lewis, the Public Utility Holding Company Act, which was also passed in 1935, says that a public utility holding company, which Middle South is, may not generate its own capacity, may not build generating capacity. You couldn't do it. Middle South Utilities couldn't do it.

So what do they do? They form a subsidiary called Middle South Energy, Inc., to avoid the Public Utility Holding Company Act, and thereby get Federal jurisdiction rather than State jurisdiction.

Mr. LEWIS. I said earlier, Senator, in both my printed, my filed statement, and my verbal statement, that we had to get approval of the Securities and Exchange Commission for the creation of Middle South Energy. We had to get their approval for the availability agreement, which is the underlying agreement among the companies with Middle South Energy.

Those were done under procedures which are prescribed, that provide for public notice and opportunity for a hearing. The idea that it was some kind of a subterfuge, that we could slip around quietly and do this sort of thing with nobody knowing anything about it, is absolutely unfounded.

Senator BUMPERS. Mr. Lewis——

Mr. LEWIS. And I'd like to know what section of the Public Holding Company Act says that the holding company could not build any facilities?

Senator BUMPERS. Is it your impression that you can, that Middle South could build a plant if they wanted to?

Mr. LEWIS. I think it's an open question, yes.

Senator BUMPERS. Well, it's my understanding that it is not.

Why didn't you do it, then? Why would you form a subsidiary?

Mr. LEWIS. That is the way our system is organized. Our holding company——

Senator BUMPERS. You've never had a subsidiary like this before, Mr. Lewis.

Mr. LEWIS. I've explained, I think, Senator, how the thing came about. It is a financing vehicle, and it worked as it was supposed to, by providing us access to capital that we could not have accessed in any other way.

Senator BUMPERS. Mr. Lewis, on January 28, 1977, you testified—and it was in a rate hearing before the Arkansas Public Service

Commission, and I believe this dealt with the Independence plant, which for the record is a big, what, 1,000-megawatt plant, coal-fired plant in Independence County, AK.

Mr. Lewis. No, sir; it's two units that are about 840 megawatts each.

Senator Bumpers. Sixteen hundred and——

Mr. Lewis. Eighty.

Senator Bumpers. You testified in response to a question from then Attorney General Clinton, now Governor Clinton. He asked you specifically: Would Arkansas be obligated for any part of the cost of Grand Gulf? He didn't ask that specific question. He asked: "Would we be required to take any of the power from Grand Gulf?" And your answer essentially was: "Not if we didn't need the power."

Now, in a court of equity, if you were going to take this not before FERC but before a jury or even a court of equity, what do you think their finding would be so far as Arkansas is concerned? Did we not have a right to rely on your answer that day?

Mr. Lewis. Senator, my answer was as true as I knew how to answer. It was factual at that point in time. And if you will look carefully at the statement, it shows that there was a change in about 1980, which was agreed to by all of the parties.

Senator Bumpers. Well, there was a subsequent change after that, in which all of the parties agreed that Arkansas Power & Light would not be required to take any power. And it was later Louisiana who challenged that agreement before FERC, that brought on this unhappy situation we're in right now.

So when you talk about that first agreement, you also had a subsequent agreement in which Arkansas Power & Light--it was agreed by all of the subsidiaries of Middle South that we would not be obligated to take any of the power.

Mr. Lewis. Senator, I'm trying to answer your question, which was about this answer I gave in 1977. From 1972 up to that point in time and even for some period after that, it was the thinking of the whole system, including Arkansas Power & Light Co. chief executive officer and representatives on the operating committee, that the way Middle South Energy would handle the sale of the capacity of the Grand Gulf facility would be to become a party to the system agreement.

Later studies indicated that that was not a workable way to handle it, and so other agreements were worked out. They were filed. All of this had to get approval of governmental agencies.

Senator Bumpers. Now, if we accept your argument on this, Mr. Lewis, and if the courts ultimately rule that this was a legitimate method of building a plant and passing on the cost, and if, further, the Congress sees fit not to change the existing law, which I think has a loophole in it big enough to drive a wagon and team through, then a subsidiary of Middle South can build any generating capacity they want to in the future, and not one single regulatory authority in any State among its subsidiaries will ever have any say-so over whether they take the power or not.

It'll be just an in-house arrangement, and our State will be absolutely powerless to do anything about it. Is that not a fair statement?

Mr. **Lewis**. Well, I don't think it is a fair statement, Senator. I'm sure you feel it is a fair statement.

Senator **Bumpers**. Well, Mr. Lewis, I don't want to be combative, but I just want to ask this simple question. You formed a subsidiary, built all this generating capacity which we can't use—we have excess capacity without Grand Gulf. I can tell you, it will make a Sahara out of my State if this decision stood. Reynolds Aluminum——

Mr. **Lewis**. Senator, I have to take strong exception to that. I think that's a gross overstatement.

Senator **Bumpers**. Well, we see that differently. I come from a State that has a median family income of less than $20,000, which is a lot less than most of the stockholders of Middle South. And I'll come back to that in just a moment.

But my point is, if you form a subsidiary to build generating capacity and you bring these chief executive officers or your operating committee, as you call it, you bring them in and you say, how much of this will you take, and they say none or some, you can go ahead and build the plant.

And under the FERC decision, which says all nuclear power will be operated on a systemwide agreement, that means no State will have any say-so over the building of that capacity, they will never have any say-so about whether they take it or not. And under the law as I understand it, the local public service commission will be required to set rates to pay for the cost of something they never had any say-so over in the first place.

Now why is that not a fair statement, because that's just what's happened?

Mr. **Lewis**. Well, in Arkansas there is a requirement that we file with now with the public service commission 2 weeks in advance of filing it in Washington anything we're going to file with the SEC.

Senator **Bumpers**. Well, I suppose that helps take care of the future problem.

Mr. **Lewis**. Your commission has information about it before we ever get it to the agency we want to file it with. And we very carefully abide by that. And I can assure you, we haven't the faintest idea or intent to try to slip around and do anything.

Senator **Bumpers**. Well, you'll have to agree that that is a common perception in my State, and I consider it to be a very understandable one.

Mr. **Lewis**. Well, I consider it a very unfortunate one.

Senator **Bumpers**. I consider the reality most unfortunate. Here we have a plant that was originally scheduled to cost $800 million, that turns out to cost $3.5 billion, and 36 percent of it is now allocated to the people of my State, 48 in per capita income.

We have a company down there called Reynolds Aluminum that pays Arkansas Power & Light $100 million a year. In my opinion, if this decision stands Reynolds Aluminum will be very hard-pressed to stay in Arkansas. If they leave, that's another $100 million that the rest of the people of my State will have to pick up, because we're talking about paying off a $3.5-billion debt.

Now, you have alluded in your statement here to the fact that Middle South has made two offers and both of them have been rejected. I'm not going to second-guess that, but there may be perfectly valid reasons why those offers have been rejected.

Now, the consumers, the consumers in Arkansas, have made an offer to Middle South, or to AP&L. And so far as I know, Middle South has rejected that out of hand, and that is one under which the people of Arkansas would labor and choke to death accepting half of their share that's been allocated to them and the stockholders of Middle South would assume the other half.

Middle South made $500 million or close to it last year, is that not correct?

Mr. LEWIS. Senator, that was all allowance for funds used during construction. That accounted for more than our reported net income. We had no cash net income. It was all an accounting transaction.

Senator BUMPERS. Well, how much did you pay in dividends?

Mr. LEWIS. We paid $1.78.

Senator BUMPERS. How could you pay for that just on a bookkeeping profit?

Mr. LEWIS. Well, it's a valid accounting entry. All I'm trying to tell you, though, is it related to the huge construction program that we had. You pay dividends out of cash. You have to have book retained earnings to cover it to legally pay a dividend and you have to have cash. But it can come from depreciation allowances, from financing from all the sources.

You don't tag your dollars. You put them in the treasury.

Senator BUMPERS. Well, let's get back to my point. I'm an old trial lawyer and I know you settle cases sometimes that you'd rather not settle because you think that you may get hurt worse if you don't settle. But I think there has been an offer made down there to AP&L that is a legitimate offer, and it's one that I cannot for the life of me see why Middle South or AP&L would find unacceptable.

That way, both sides accept a burden. We have a 300—we have roughly a 300- to 400-percent cost overrun on this plant. We have a judgment that was made about what the demand for energy was going to be on this system that was unfortunately terribly erroneous.

And utility companies—and I am not antiutility, but I really resent, I really resent utility companies being able to make the same kinds of bad judgments that other corporations make and pass those bad judgments onto innocent people. If you were out in the private sector and you were not a monopoly being regulated by FERC or the States, I don't know what would happen to Middle South, but it certainly wouldn't have this result.

Other corporations live with their bad mistakes and their decisions. But here it's being passed on to an innocent people. I don't say that to be political or populist. It is a fact.

Now, why is that offer not one that you could seriously entertain?

Mr. LEWIS. Senator, the information I have about the offer, as you put it, was a letter written by a lawyer on the staff of the public service commission named Waldron, who wrote it to Mr. Gerry Jackson, an attorney for Arkansas Power & Light Co. He wrote it on a Thursday, I believe, and called Jackson on about

Friday and says, that's a serious offer and we have to have your answer by Wednesday.

Now, frankly, it's not just as simple as might have been described here. And what I know about it, it is an offer which is modeled after the one Mr. Mac Norton, former chairman of the commission in Arkansas, who represents industrial customers in these proceedings, also floated in a letter to the same lawyer, Mr. Gerry Jackson.

He did not put it into the record of the hearing that was going on. We have no indication as far as I know that the public service commission would approve that. Mr. Waldron doesn't speak for the public service commission.

Senator **Bumpers**. Well, the press has indicated that the public service commission itself has recommended this settlement.

Mr. **Lewis**. Well, I don't know to whom they recommended it.

Senator **Bumpers**. You're not aware of the public service commission making this same offer to Middle South?

Mr. **Lewis**. All I can tell you is that I am told by Mr. Jackson by telephone that he received a letter from Mr. Waldron, a lawyer on the staff of the commission, floating an idea for a settlement, and then received a telephone call which said, this is a serious offer. But it was less than a week's time that they put on it for consideration.

Senator **Bumpers**. Well, let me ask you this here in this hearing. Are you willing to consider such an offer?

Mr. **Lewis**. We are willing to talk with anyone who is serious. I frankly think that offer, from what I know about it, is unworkable. I don't think that Middle South could survive with that offer.

Senator **Bumpers**. Well, how about the ratepayers' survival? That's important, too, isn't it?

Mr. **Lewis**. Well, the ratepayers' survival—under the plan that was proposed to the Arkansas commission, it would have had an increase of less than 6 percent.

Senator **Bumpers**. The first year.

Mr. **Lewis**. That's right. And over a 10-year period, less than 12 percent, spread over 10 years. Now, I have great difficulty—I'll be honest with you—in seeing that as an economic Sahara.

Senator **Bumpers**. Well, you know, there are other things beside Grand Gulf that are involved. You're in there right now for a $200 million rate increase in addition to Grand Gulf. But I'm not going to burden this record with all of that.

But what is the ultimate cost? You're talking about the first 10 years, and then what does it go to?

Mr. **Lewis**. I'm not sure I know exactly how you want me to express that.

Senator **Bumpers**. Well, my point is you're only agreeing that the Middle South stockholders will bear some of this burden during a short period of time, and then that phases out and the people of my State are left to absorb the entire burden.

Mr. **Lewis**. Well, my recollection of the numbers—and my memory could not be precise on this—is that the offer was for the stockholders of Middle South Utilities to bear as a permanent loss $400-some odd million during that, as you called it, brief period of 10 years. That's not an insignificant sum of money.

And you might be interested, these stockholders, 44 percent of them are 65 and older, 49 percent are already retired, over half of them have less than 200 shares, which at present market value is about a $3,000 investment. So if you have in mind that we're talking about some big fat cats on Wall Street who could care less about how things go, these are real life and blood people.

Over half of them, as I'm saying, are elderly, retired; small investments; dependent on their dividends for part of their livelihood.

Senator BUMPERS. Mr. Lewis, I invest in the stock market, and I want you to know I have lost some money from time to time on the stock market because of bad decisions on the part of management. That's the way our market works in this country.

And if you made $500 million last year, you can call it paper profit, call it whatever you want to call it, my point is that we have—I want to resolve this matter. I can tell you that it's hanging over my State like Damocles' sword, and that's the reason I'm questioning you about this settlement offer.

Try to resolve it in a way that will not break Middle South, but will not allow you to make the same kind of profit, or to profit from what I think was a bad decision many years ago, but one that will not burden the economic development of my State. We're already a poor State.

Now, let me just conclude. we're going to have to go vote here in a minute. Let me just ask you a couple of concluding questions.

No. 1, are you telling me that when you discovered that the soil at Grand Gulf Two, the soil conditions there came as a surprise to you and you decided to move both plants then to the Grand Gulf location, it was at that point you decided to form the subsidiary, Middle South Energy, Inc.?

Mr. LEWIS. It was, yes, in that period of time, that's right.

Senator BUMPERS. And you're telling me that, out of an $800 million anticipated cost at that time for Grand Gulf—that was Grand Gulf One—that that 25 percent difference in the soil there was enough to justify saying: Mississippi, you can't handle this any more; we're going to form a subsidiary to finance this thing?

Mr. LEWIS. What I'm trying to tell you, Senator, is that in that whole process, when the soil borings and further investigation indicated that it would cost 25 percent more to build the same unit at this New Orleans site as compared to the Grand Gulf site, and we felt that was enough of a difference to justify relocating because the site could handle both units, and we looked then at that project in relation to the size of Mississippi Power & Light Co., and in fact any of the companies in the system, it became clear that we had to find some other financing vehicle to carry the project forward.

Yes, sir, I'm telling you that.

Senator BUMPERS. Do you agree with the FERC decision?

Mr. LEWIS. I do not at this point in time think there's any question but that FERC had the authority to make the decision. I would not say the decision they made was the only decision they could have made. I give FERC credit for doing a very thorough job of having a long hearing, giving everybody every opportunity to put in the record anything that they wanted to, an extensive record, carefully researched over a long period of time.

And I think it's unfortunate that people have made the statements about FERC not being a valid basis, a valid forum for deciding this sort of thing. I think FERC——

Senator BUMPERS. It is a valid forum and I—you know, I hate to say it, but I have to begrudingly admire the crafty way you went around, getting to FERC instead of the Arkansas public service commission, where the outcome would obviously have been considerably different.

Mr. LEWIS. I don't know how we could say what that outcome would be if they're a fair forum and are going to listen to everything before them, Senator.

Senator BUMPERS. Well, I know one thing. Arkansas signed a 17.1 percent guarantee when this financing was originally set up, and we never—and incidentally, that was not approved by the Arkansas public service commission. That was something Arkansas Power & Light did originally, they agreed.

And even the systemwide agreement they signed, that let Arkansas off scot-free, still would not have relieved Arkansas Power & Light of the 17.1 percent obligation they had on the original financing, isn't that correct?

Mr. LEWIS. That is correct, and the reason is because an awful lot of money had been borrowed from banks on the basis of those underlying agreements, and the banks were not willing to let anyone out.

Senator BUMPERS Well, my question is, you have not said whether you agree with the FERC decision, but if you put the worst possible light on it from Arkansas 'standpoint we would be obligated for 17.1 percent of the plant. How on earth do you get the 36 percent?

Mr. LEWIS. Well, I didn't come up with that number, Senator.

Senator BUMPERS I certainly didn't.

Mr. LEWIS. The FERC came up with the number. We had never proposed that. I think if you will look at the record that was made in those cases, you will find that the case that was put on by Middle South Energy and the system was in support of the agreement as filed, and I've never heard even any of the lawyers from Arkansas say anything other than that a good aggressive case was presented.

Senator BUMPERS. Well, of course being aggressive is one thing; being right is something else. You know, they say——

Mr. LEWIS. Well, the FERC decided differently.

Senator BUMPERS. I forget the old saying, I hear Fritz Hollings quote it all the time: If you've got the facts on your side, argue it to the jury; if you've got the law on your side, argue to the judge; and if you don't have either one, just run around and hoot and holler. So aggressiveness is really not the key to the correctness of a decision.

You mentioned a moment ago, Mr. Lewis, the fact that Arkansas has passed a law in the wake of this whole controversy. And I can't overly dramatize this for the record, but this is easily the most potentially devastating economic event in the history of my State.

But you stated a moment ago that you couldn't do this again because Arkansas has demanded 2 weeks notice. No. 1, you're required to give them notice. That still doesn't keep you from doing the very same thing. Arkansas can't keep you from forming a subsidiary.

No. 2, a Federal judge has already ruled in Arkansas that Federal law on this question will preempt State law, that these are wholesale sales of power and Arkansas public service commission has nothing to do with it.

So in short, the Arkansas law that we've just passed probably is not worth the paper it's written on if you choose to go through the same modus operandi again, is it?

Mr. LEWIS. Well, I can only assure you, sir, that we have very carefully observed that requirement and filed with the Arkansas commission on the schedule required everything that they say is required.

Senator BUMPERS. Now, finally, under the systemwide agreement that FERC has imposed upon Middle South's subsidiaries, which deals only with nuclear—and the only nuclear power that Middle South has on its entire system are the two plants that AP&L built in Arkansas, one just before I was elected Governor and one while I was Governor.

Those plants were built, by today's standards, very cheaply, and little cost overruns, by today's standards nothing. And those plants, as you correctly point out in your statement, the front end loading on the cost of those is the greatest. As the plant operates longer, the power becomes cheaper.

And we built those plants in anticipation of our needs, and now they've both been on stream anywhere from 10 to 15 years, so that the cost is negligible. Not only are we going to have to absorb 36 percent of Grand Gulf, we now must share Arkansas Nuclear One and Arkansas Nuclear Two with the rest of the system, the cheapest power the system has.

Does that sound fair to you?

Mr. LEWIS. Sir, I think that's incorrect.

Senator BUMPERS. Tell me what is correct.

Mr. LEWIS. Well, so far as I know there is nothing in the FERC decision that gives anyone access to any of the output of Arkansas Nuclear One, Unit One or Two. I don't know to what you're referring.

Senator BUMPERS. It may be that somebody on the system—it may be that Louisiana, it may be that Louisiana or Mississippi or somebody else, may have to file suit to effect that result. But as I understand the FERC decision, that's exactly what it says. It says the nuclear power of Middle South has and will continue to operate on a systemwide arrangement.

Mr. LEWIS. I think that's incorrect, Senator.

Senator BUMPERS. Well, I tell you what. Let me submit that statement, that question for the record, Mr. Lewis.

Mr. Chairman, I don't want to take all of the committee's time this afternoon. There are others who have questions. I appreciate your indulgence in allowing me to take the time I have on this issue, and I would like to reserve the right to ask additional questions in writing of Mr. Lewis.

Mr. LEWIS. I'll be glad to respond.

Senator BUMPERS. Thank you, Mr. Lewis.

Mr. Brown, you're a very patient witness.

The CHAIRMAN. I know of the Senator's interest in this subject, and I wanted to give the Senator the opportunity to ask the questions. I think the other members of the committee have been patient enough to allow that to happen as well, and I appreciate your concern.

We will, of course, entertain the written questions and the responses to the record.

Senator Hecht.

Senator HECHT. Thank you, Mr. Chairman.

A question to Mr. Lewis. What are some of the justifications being used by the regulators to reject or reduce the retail rate requests?

Mr. LEWIS. Well, some of the things that are being said is that there was imprudence in the cost overruns, the amounts that Senator Bumpers had referred to. On that, I'd like to point out that the Mississippi Public Service Commission had an audit done of the construction and expenditures and schedule of Grand Gulf by Decision Management Co. and Burkhalter & Company, and a copy of the executive summary of that is attached to my statement, so you can see.

And they in effect said the company is not responsible for any of the overruns, that it had to do basically with regulation, with changes in standards, with the TMI, post-TMI regulations, and things that are all enumerated there. They also said that it's a matter of not needing any of the capacity. Senator Bumpers also made reference to that. And they have said that they did not have a chance to approve the contracts.

I've indicated that those contracts were required to be filed and approved with and approved by the SEC. Notice was given of those filings. Anyone who wanted to participate, who had a legitimate interest, could have requested a hearing and participated on that.

So those are basically the kinds of things that are being said: We don't need it, it's excess, it's imprudently built, things of that sort. We think there are adequate answers to all of those.

Senator HECHT. What will be the effects of the so-called rate shock associated with Grand Gulf, and do you propose to alleviate it?

Mr. LEWIS. Well, the matter of getting billions of dollars put into the rate base is a serious concern. All of our companies in their applications to the State commissions to get this put into the rate base and to get retail rates to reflect it have proposed what we call phase-in plans, which spread out over a period of years the impact, instead of taking it all in 1 year.

And we mentioned in the conversation with Senator Bumpers that the amounts in Arkansas would be less than—I think without the settlement—those numbers I was using related to the settlement that we had offered—would be on the order of 7.7 percent the first year, and total over 10 years about 15 percent increase in rates.

It would be about 14.5 percent in Mississippi, at Mississippi Power & Light Co., who have been allocated 33 percent of Grand Gulf. It would be less than that in the two Louisiana companies, except that—and this need to be made clear, I think—Louisiana Power & Light Co. was allocated only 14 percent of Grand Gulf, but they have an 1,104 megawatt nuclear unit, Waterford 3, that is going commercial right at this time. It's ready to go commercial, and they're taking all of that in their rates. And that got into the allocation.

So what we're doing is phasing in over about a 10-year period the impact of the rates that will be required, and we feel that this will soften the blow on our customers.

Senator HECHT. Thank you.

It is claimed that your company never sought and was never given permission to build Grand Gulf by the Arkansas public service commission. Why is this?

Mr. LEWIS. The reason is because there was no legal requirement that it be done and, beyond that, no mechanism. There was no procedure for going to a commission and asking for an approval for a plant outside the State of Arkansas. So at no time during the construction of Grand Gulf—and there was an awful lot of talk about it. We put out a lot of information. It was involved in rate proceedings, as Senator Bumpers indicated, back in 1977 and what-not.

There was never any requirement that we get permission from the Arkansas commission, and no procedure for getting such. It would have been an advisory action.

Senator HECHT. Thank you very much.

No further questions, Mr. Chairman.

The CHAIRMAN. Senator Johnston.

Senator JOHNSTON. Thank you, Mr. Chairman. Mr. Chairman, let me say, we share a lot of things in common with Arkansas—a border. We say as a joke sometimes we share voters sometimes. [Laughter.]

At least I try to get some of my Arkansas friends to come down, vote early and often.

We share problems of poverty. We've got an awful lot of poor people in Louisiana and more of them coming in all the time. Our unemployment rate is actually second in the country, second only to West Virginia, and getting worse. We're losing industries all the time, losing them because of power rates, because natural gas prices are going up.

You say Arkansas is going to become a Sahara. We have a lot of people in Louisiana who think we've already gone in that direction. So it is with full sympathy and self-preservation that I come into this hearing.

We are sort of looking for the original sin and the original sinner here. And I'm not here to defend Middle South Utilities, except to try to be a little factual. And I want to point out something about this whole nuclear industry that is never being said these days. It is something I feel very deeply, and that is that a great deal of the fault of the nuclear industry is with the regulators and with those of us who made the rules for the regulators.

I just got back from Japan. I made a speech over there to the Japanese Atomic Industrial Forum, got the facts from them, talked to their people. You know, they're building nuclear plants in Japan in 5 years, when it's taking us 12, 13, 14 years. They're building them at half the cost we're building.

Their scram rate is a fraction of what ours is, which indicates that they not only build them better, faster, cheaper, but they build them safer. And why is that? It's because we have built a regulatory system designed by lawyers, for lawyers, that produces only delay and legal fees and ill serves the public.

Now, that's what I think to a large extent is the original sin on Grand Gulf. That is our regulatory system produced a cost overrun that made the cost of the plant go from what, $800 million to what was it?

Senator BUMPERS. About $3.5 billion.

Senator JOHNSTON. $3.5 billion. I'm not here to make the final judgment that Mississippi Power & Light in their study was correct when they said that there was no fault on behalf of Middle South. But I do know, I know for a fact—at least I believe it to be a fact—that much of the delay was generated by the regulators.

Now, maybe it was generated by the regulators in good faith. I don't doubt that for a moment. But the rules change. I remember, for example, you had that generator problem where you had to tear out a generator and rebuild it when you wanted to go to a low power license, and these were about—how many redundancies in that generator? The problem was in about the fifth redundancy?

Mr. LEWIS. Yes.

Senator JOHNSTON. In other words, they had five different sources of electric power going into Middle South, and they identified this generator, not that it was faulty, but one similar to that had misfired up in New York somewhere, one out of very many. And here's the fifth redundancy, and it stopped them from going to low power. I mean, if the first source of power failed, which is the grid, and then the second source, then the third source and the fourth source, and this was the fifth source going to a low power license.

But no, what did the NRC say? They said you had to shut the whole thing down. You could not go to low power, at a cost of how many million dollars a day? Was it about $1 or $2 million a day?

I don't know how many things like that occurred during the construction of this plant. It is fashionable these days to dump on the electric power industry because they have had all these delays. But I would invite our friends of the press to look into some of these questions.

I mean, was that really necessary, to shut the whole plant down at millions of dollars a day because your fifth redundancy generator, which itself was not faulty, had to be rebuilt simply because one in some other area had been rebuilt? The list of grievances, it seems to me—and they're not grievances against Middle South; they're against the ratepayers, because these ratepayers in Arkansas are going to have to pick up that tab. They're going to have to pick it up in Louisiana as well.

And all across this country I believe we're going to have power shortages. We're going to be paying a lot more for our electricity. Now, whose fault is that? It may be right here, right with us on this committee, because we haven't redesigned the system.

How do the Japanese do it? Well, as I say, their system is not designed by lawyers for lawyers. And I used to be a lawyer.

Mr. LEWIS. I understand there are only 12,000 lawyers in all of Japan.

Senator **Johnston**. We graduated more lawyers last year than there are in all of Japan—more lawyers. And I'm not against lawyers. [Laughter.]

Senator **Bumpers**. Some of my best friends are lawyers.

Senator **Johnston**. But I really think that point needs to be made. Now, that's the No. 1 point, and I don't know what we can do about it as a practical political alternative.

Do you think you can change the NRC and suggest doing away with some of these delays? Oh, no, we need that for safety; we need to have hearings from here as far as the eye can see, so all these lawyers can go make fees and cause delays.

And in the meantime, don't worry about, those of you who are opposed to nuclear power. There is not going to be any more nuclear power. You're not going to be able to build a nuclear plant in this country. I don't know when you're going to be able to build it, if ever, until after the next big shortage. And I think that's a shame.

As a matter of fact, you can't even build any coal plants. You've got a different set of problems there, but the regulators of a different kind are causing those problems, too.

Now, let me just ask a question or two about——

The **Chairman**. Could I intervene for just a moment?

Senator **Johnston**. You may indeed.

The **Chairman**. And say, gee, I wish I had said that. [Laughter.]

Senator **Johnston**. I thank the distinguished chairman.

Now, back here when you formed that little unit, what do you call it?

Mr. **Lewis**. Middle South Energy?

Senator **Johnston**. Yes; that was formed back in 1974. That was before TMI. Nobody complained about that at the time because nobody figured rates were going to go up. They figured everything was going to be played by the old rules instead of the post-TMI rules. Isn't that really right? Isn't that part of the problem?

Mr. **Lewis**. Well, Senator, this was not the first time that a special-purpose subsidiary had been formed by a holding company. There was precedent for this in the AEP system and in New England, where special-purpose corporations——

Senator **Johnston**. Oh, I'm not either justifying or not justifying. I'm just saying nobody cared at that time because it didn't look like Grand Gulf was going to be a big, expensive cost overrun. That was prior to TMI and prior to the rules changing.

Now, back in the old days, the sixties and seventies, you had some pretty low-cost gas units in Louisiana, didn't you?

Mr. **Lewis**. Yes, sir; we certainly did.

Senator **Johnston**. And you shared that low-cost power with Arkansas while they were building their coal and nuclear powerplants, didn't you?

Mr. **Lewis**. Yes, sir; I testified in one of those proceedings—I don't know whether it was the same one Senator Bumpers referred to or not—that we'd done a calculation that showed that within a period of a few years the people of Arkansas had benefited about $30 million, if I remember correctly, by having access to energy from Louisiana gas powerplants. That doesn't sound like much now, but we thought it was big money back then.

Senator JOHNSTON. Well, in effect we did operate it as a systemwide system at that time.

Mr. LEWIS. Yes, sir; that's right. And frankly, the first nuclear units in Arkansas could not have been handled by Arkansas Power & Light Co. by itself without being a part of a bigger system, because the size of the unit would have been an unwise thing for them to build as a stand-alone company.

So it's all been part of a system approach from the day go. These four companies have operated under common ownership since the late 1920's, so it's nothing new. It's been around a long time.

Senator JOHNSTON. The difference here really is that these costs were going up ever so slightly and then all of a sudden they spiked up because of—really, because of post-TMI problems. Isn't that the main problem you had here, post-TMI problems, that plus——

Mr. LEWIS. The auditors broke out the TMI-related increase in costs and it I think was about the third of the categories. The largest category was simply regulatory requirements. It was just increased regulation, I think, that they could not directly relate to TMI.

Senator JOHNSTON. I know, but TMI caused the change.

Mr. LEWIS. Well, that was a watershed in terms of regulation, no question about it.

Senator JOHNSTON. I mean, the regulators were scared of their shadows. They still are. TMI Unit No. 2, how long did it take them to finally make up their minds on that down there?

Mr. LEWIS. Well, since 1979.

Senator JOHNSTON. Their deliberations went on for 5 years, with hearings on and off. I don't know whether it's good or bad. I'm not defending the safety decision or criticizing the decision.

What I'm criticizing is 5 years to make that decision. What was it, how many thousands of pages of record? How many, 30,000? Thirty thousand pages of record. Do you think that the NRC Commissioners are capable of reading and understanding 30,000 pages of record and being able to get a more safe result from that? That's the most absurd, asinine thing I think I've ever heard.

And they're scared of their shadows. I'm not saying that they should have decided it yea or nay, but they didn't need 5 years and they didn't need 30,000 pages. And it's time we woke up in this country. I think it is just absurd. I mean, that's not free. All those lawyers' fees and all that $1 million a day delay. How much a day does it cost?

Mr. LEWIS. Well, it's about $1 million a day.

Senator JOHNSTON. And all that $1 million a day, that's not free. That's paid by those people in Arkansas who make an average of less than $20,000 a year.

The CHAIRMAN. Could I interrupt just a moment? The $1 million a day isn't all attorneys' fees. [Laughter.]

Mr. LEWIS. No, sir; it's basically interest on the capital invested in the plant.

Senator BUMPERS. There are a few attorneys fees.

The CHAIRMAN. The reason I asked that, in my area of the world you can almost tell whether a law firm has any standing with the public at all, because if they do they have some part of the action in the lawsuits around WPPSS, and if they don't they obviously don't amount to much. And I say that with due apologies to those few that don't have any part of the action.

But the attorney fees the last time I saw them were amounting to $200,000 a day for the members of the Public Power System alone. That doesn't include all the rest of the people.

Senator JOHNSTON. If this $4 billion odd increase in costs were all going to the attorneys I might not complain. My father used to say, when I joined him in a law practice, that the safety of the Republic lies in a well-paid bar. But this is a very safe country if that is the proper standard.

And I don't mean to dump on individual attorneys who bring suits. That's their job in an adversary system. It is our problem that we created a system designed to produce winners, losers, and designed to produce decisions rather than safety requirements. And that is the basic problem.

I wish we could do something like the Japanese do. Maybe we need to bring Japanese managers over here, like we build Toyota plants. They have some methods there that are helpful to us. Maybe those methods would be helpful with nuclear power.

In any event, it hasn't helped much——

The CHAIRMAN. We might bring the Diet over instead of the Congress.

Senator JOHNSTON. Now they're starting meddling.

Well, Mr. Lewis, one final question. I think it should be mentioned here that Arkansas did have a chance to settle this at a considerably cheaper percentage than they ended up getting hit by with FERC, did they not?

Mr. LEWIS. Yes, sir; there have been settlement offers. The first one would have had them take 17.1 percent of the plant for 5 years and then, as I recall, about another 10 or 11 percent at the end of 5 years.

Senator JOHNSTON. I hope the matter can be settled now, because I don't think it's in the interest of anybody to get caught in litigation that goes on and on. It's not in the interest of my State. It's not in the interest of the country.

I would urge Middle South to be as generous with its stockholders' funds as it can, because what I'm hearing from my esteemed colleague from Arkansas is that they're going to be looking to those stockholders. And I would hope it could be settled on a reasonable basis, one that allows Middle South to survive, its stockholders to survive, but without having some pretty bad precedent set that will lower bond ratings for all electric power companies throughout the country. I would hope that that could be done.

Thank you, Mr. Chairman.

The CHAIRMAN. Thank you, Senator.

I think the exchange that has taken place here this afternoon is illustrative of one of the difficulties the utility industry faces. It may be that the Middle South situation is unique in some respects. It may also be that the fact that it's a nuclear plant makes it unique in some respects.

I think there are others who could point to coal-fired plants that have caused the same kind of difficulty and coal-fired plants that have the same difficulty, the same set of difficulties that is now demonstrated here. But I share the convictions as stated by the distinguished Senator from Louisiana. I interjected a moment ago I wish I had said that.

As a matter of fact, I do, because I believe that we in the Congress are guilty in part for having created the situation, and in a larger part for having tolerated a situation that has developed in which delay is the norm rather than the aberration, and delay is the thing that costs the most money.

What was the interest rate anticipated at the time you started Grand Gulf?

Mr. LEWIS. I'm not sure of that number, but I would conjecture that it was probably in the 7- to 8-percent range.

The CHAIRMAN. And what have you had to pay on borrowed capital?

Mr. LEWIS. We've paid in excess of 20 percent during some periods.

The CHAIRMAN. Now, if you anticipate a 7-percent rate and a 7-year construction period and you go to a 20-percent rate and a 15-year construction-licensing period, what does that do to your costs?

Mr. LEWIS. Well, the largest part of the total increase in cost was in cost of money. It was over a billion. I think it's about $1.1 billion. Forty-eight percent of the cost increase is in allowance for funds, which is time and interest rate.

The CHAIRMAN. Time and rate.

Mr. LEWIS. Yes, sir.

The CHAIRMAN. We also, during that same period of time since you started Grand Gulf, have gone through a period when there was relatively rapid inflation in all costs, materials and labor. If I recall correctly, the construction index of inflation ran higher than the general index of inflation.

Mr. LEWIS. That's right.

The CHAIRMAN. And at times was around 14 to 15 percent a year, am I not correct?

Mr. LEWIS. That's correct.

The CHAIRMAN. And that by itself would double costs in 5 years.

Mr. LEWIS. Yes, sir.

The CHAIRMAN. And instead of a 5-year delay, you've got at least a 10-year delay, nearing a 10-year delay.

I agree with my colleague from Louisiana. That's one of the reasons, not the sole reason, but one of the reasons for these hearings, which is to try to find some answers to questions.

Mr. Brown, you did a good job in setting forth the questions to ask us and challenging us to come up with some answers. If I have any criticism of your testimony, it is that it's short on answers as to what we could do. And I'll not take the time now because the vote on the floor of the Senate is imminent, and we do want to get to the remaining panel for today.

But I would invite you to give us a list of specific suggestions of what we might do in terms of changes in statute. You suggest the conflict in jurisdictions, there ought to be a way to force people in the agencies to coordinate their activities. It's a good suggestion, and to the extent that you can, would you beef that suggestion out, fill it out with a little bit of structure as to how you would accomplish that.

Mr. BROWN. Yes, sir; I will.

The CHAIRMAN. Because I for one, and I think my friends on both sides of the aisle on this committee are very concerned about the situation that confronts us and the costs that the consumers of this country are going to pay, both in terms of their rates and also in terms of the quality of service which they receive from utilities.

And I know you're concerned about both. You can look at it from a different standpoint than we, and we seek your advice earnestly and sincerely into the things that we might suggest and might be able to further in the Congress as to how we get through the regulatory nightmare.

I know that following TMI, a distinguished commission was appointed to determine whether or not there were things that should be done by the NRC, or with respect to the NRC, differently, and that commission report was widely hailed by many, and almost none of the recommendations of the Kemeny Commission has been implemented. None of those that require statutory change has been implemented.

Now, I don't think we can blame you and I don't think we can even blame the NRC wholly if indeed the Congress, having been given some suggestions, has done nothing to implement those suggestions. And I invite you to put us on the spot somewhat further by making more suggestions about what we might do in specific details as far as you're able to do so.

Gentlemen, thank you very much.

Senator BUMPERS. Mr. Chairman.

The CHAIRMAN. Senator Bumpers.

Senator BUMPERS. A couple of quick observations. First of all, Mr. Lewis, I want to say that it seems to me that Middle South and some of its subsidiaries are headed on a course which ultimately may be devastating to both Middle South and the subsidiaries, especially AP&L in Arkansas. If we win everything we're asking for, that'll be very devastating to Middle South. If we don't, it'll be devastating to us.

I have said publicly that the last offer AP&L made was a step in the right direction. Some of the people at AP&L are very good friends of mine and they're good people, and they have an honest desire to resolve this thing as amicably as possible to the benefit of both parties. And I have that same feeling.

I don't think the settlement offer you made the last time was enough, but I think that a long protracted public process is probably not going to help either side. So I strongly urge and devoutly hope that this matter can be resolved and put behind us in a way that will not be so devastating to us or to you. I have no desire to see Middle South go under. I have no ill will toward any Middle South stockholders. I know a lot of them, too.

And one other thing that I might ask is, right now Lousiana is buying most of the power from what we call Independence, the big coal-fired plant that I referred to earlier, 1,680 megawatts. Now, when Waterford goes on stream, does that mean they will quit buying power from Arkansas Power & Light out of that plant?

Mr. LEWIS. Senator, they are buying power out of the White Bluff plant.

Senator BUMPERS. I'm sorry, White Bluff. I'm sorry, I didn't mean that.

Mr. **Lewis**. Mississippi is buying the Independence plant.

Senator **Bumpers**. I'm concerned about the Waterford. When Waterford goes onstream for Louisiana——

Mr. **Lewis**. Yes, sir, the contract——

Senator **Bumpers**. [continuing]. They will quit buying power from White Bluff?

Mr. **Lewis**. The contract is a short term contract under which Louisiana Power & Light Co. and New Orleans Public Service bought the output of White Bluff. It by its terms terminates when—partially when Grand Gulf went commercial on July 1. I'm not sure of the exact proportion. I just don't remember those details.

And when Waterford 3 goes commercial, which is now expected to be in the early part of August, it will be terminated, yes, sir. And that is one of the issues that is before the Arkansas commission in the rate case that they have going on at the present time.

Senator **Bumpers**. Mr. Lewis, you also alluded earlier to the fact that Arkansas passed a law that requires that they be given a 2-week notice. As a lawyer, not a constitutional lawyer, but as a lawyer who knows something about Federal law usually preempting State law, you pointed out that that law would keep something like this from happening again.

Just to be on the safe side, would you have any objection to a Federal law similar to that being enacted to make sure that it doesn't?

Mr. **Lewis**. Preserving the right to closely inspect the language, in principle I have no problem with that. As I told you, we're living with it in Arkansas. I'd rather not have it. Anybody—it's just another regulatory step you've got to go through, and you've got to do things, tell somebody before, and we're often on a tight time schedule and it really gets to be a burden.

But it can be lived with.

Senator **Bumpers**. Well, you know, public service commissions are there to protect the ratepayers. They have some rights, don't they?

Mr. **Lewis**. I told you, Senator, we have religiously filed everything exactly as required by that law.

Senator **Bumpers**. Well, one other point. In answer to Senator Hecht's question, you stated there was no mechanism to do this any differently. If the subsidiaries of Middle South had simply each agreed to buy a part of the plant, rather than to buy power in interstate commerce, then FERC would not have had exclusive jurisdiction, would they?

Mr. **Lewis**. They would have had jurisdiction on any transactions among the companies.

Senator **Bumpers**. In which there was an agreement to buy power. But I'm talking about the cost of the plant itself.

Mr. **Lewis**. I don't know the answer to that, and I was not referring to that when I answered Senator Hecht. I was talking about no procedure for us to get approval from the Arkansas public service commission, which I understood was the thrust of his question. And in the opinion of Mitchell, Williams, Seely, Jackson & Tucker which is attached to my statement, the fact that there was no procedural mechanism for securing an expression from the Arkansas commission is set out by Gerry Jackson. I assume that is correct.

Senator **Bumpers**. Well, he's a very good friend and an able lawyer. But my point is this: If they had been agreeing to buy a part of the plant, they would have had to get approval of that from the Arkansas public service commission. And as long as they're just buying power, then FERC has exclusive jurisdiction to the exclusion of the public service commissions.

Mr. **Lewis**. I don't know the exact answer to that. I can only tell you that Mr. Barr of Morgan Stanely in his testimony to which I made earlier reference pointed out that, had the approach of joint ownership, discrete segments being owned by each of the companies, been the approach chosen, that the plant would have run into very severe financing problems, because it was during that construction period—you may remember this, Senator Bumpers—that the White Bluff plant which was being built by Arkansas Power & Light Co. in the midsixties had to be shut down for about 2 years because that company got into such bad financial conditions.

So there was no way it could have carried its share of Grand Gulf on a joint ownership basis during that period, because it couldn't even carry its own construction program there at White Bluff.

Senator **Bumpers**. Mr. Lewis, thank you very much.

The **Chairman**. Gentlemen, thank you both, and to you, Mr. Brown, for your patience while we were examining the other matter in very great detail. I appreciate your testimony.

I think I will ask for a recess while we go attend the quorum and the vote on the floor of the Senate. And in our absence, I wonder if the members of the final panel could take their place at the witness table so that we can get started promptly upon our return.

Thank you. The committee will stand in recess.

[Recess.]

The **Chairman**. The committee will come to order.

We not only lost our audience, we lost our witnesses.

[Pause.]

The **Chairman**. I apologize for the length of time it has taken to arrive at this time to hear this panel, and I'm not going to abuse the panel, but I will suggest that if you can summarize your testimony it would be helpful in view of the time that we have remaining for us to sit.

Mr. Vial, you're our first witness.

STATEMENT OF DONALD VIAL, PRESIDENT, CALIFORNIA PUBLIC UTILITIES COMMISSION

Mr. **Vial**. Thank you, Mr. Chairman. I have gone through my prepared statement about four times, chopping it down each time. I'll do my best to keep it short.

I start out by pointing out that I think the key to gaining some insight into the important issues that you have raised today is the recognition of regional diversity in these United States. Unlike some other States in the Nation, California projects a strong buyer's market for electric power well into the 1990's.

Our California energy commission, which is responsible for projecting on the long term, projects that we will need a total of some 21,000 megawatts of resource additions capable of generating some 40,000 gigawatts of electricity over the next 12 years. However, the array of identified projects in California exceeds the need for resource additions by a wide margin, and to my testimony I have attached two charts that show just that.

On the demand side, this represents quite a change from what was projected in the 1970's, when we were forecasting that 100,000 megawatts of electricity would be needed by 1994 and when California utilities were planning on building 40,000 megawatts of nuclear powerplants. By 1984, demand projections had been cut in half.

On the supply side, California can probably satisfy a large part of its needs with surplus power from the Northwest and the Southwest. Enough energy is available from the Northwest alone to satisfy all of California's 40,000 projected gigawatt hours of need. In the Southwest, California utilities are now negotiating for about 940 megawatts of capacity and 6,700 gigawatt hours of energy from that region, and another 20,000 gigawatt hours may be available, amounting to more than half of the total need that's projected in the next 12 years.

In the State, large amounts of power are also available, mostly because of the rapid development of nonutility generating plants, a phenomenon which is probably the most significant change in the electric market on the supply side. Under PURPA and comparable State legislation, we have implemented avoided cost pricing through standard offers to encourage the development of alternative energy technology and to promote conservation.

As of the end of April 1985, projects totaling 13,000 megawatts had received signed contracts from California utilities and approximately another 8,000 are under consideration, and recently we suspended our interim long term offer because there are about 4,000 additional megawatts pending in cogeneration in the enhanced oil recovery market related to the changes that are taking place in the gas markets.

As a result of activity pursuing conservation, load management, and alternative energy technologies for electric generation, California now faces an abundance of supply alternatives well into the 1990's. In recognition of this fact, California utilities are now planning—are not planning, I should say, to build any new large base load plants in California for at least the next 8 to 10 years.

High prices have accompanied this abundance, of course. California's industrial electricity costs, which were below the national average 10 years ago, are now higher by 47 percent. But despite this increase, and through the efficient use of energy, California, as you know, in the last expansion in manufacturing outpaced the rest of the Nation and in the recession it fell back less than the rest of the Nation.

So our industry has been adjusting to these changes. Nevertheless, having depended a great deal on fossil fuel before the energy crisis, yet we got caught up in that, and of course there were the nuclear plants and the overexpenditures there that also added to the price problem.

But we have another problem here that's coming up on the horizon that I would like to call to your attention, and that is we are facing higher and higher rates for surplus power from the Bonneville Power Administration and other sellers in the Northwest. BPA has raised its rates for surplus power continuously over the past several years. Prices for power are now in many cases very close to what we would have to pay to generate our own power from natural gas. Furthermore, Bonneville has decided to exercise monopolistic control over the intertie between the two regions to prevent competition from driving prices down to more reasonable levels.

Hence, the dilemma facing California for the remainder of this decade is to devise an energy policy that will result in more affordable and more competitive levels of electricity prices. As regulators, we need to ensure that California only invests in cost effective supply alternatives. To achieve this, the public utility commission has embarked on a regulatory strategy of using pricing to the extent practical as a mechanism for determining what should be built in California.

In implementing PURPA, we recognize the value of establishing benchmark prices or what we call avoided costs that a QF could automatically receive. These benchmark prices are designed to reflect the operating costs, the shortages, and/or capacity costs that the utility avoids by having the QF sell its power into the grid.

This approach is not just used in QF's. Increasingly, the California public utilities commission has chosen to review all utility generation projects and conservation projects using the same pricing benchmarks that we use for QF third party alternative energy pricing.

Now, in addition, the commission has actively encouraged expanded cooperation with neighboring regions of the country. Expansion of intertie capacity between the Northwest and California, for example, would reduce the joint operating costs of both regions' systems by literally billions of dollars over the coming years. This is because a price anywhere between BPA's production cost and less than our avoided cost will share the benefits between the two regions.

That is to say, we are seeking to buy the energy, of course, at their marginal costs. They want to sell it to us at our avoided cost, and there's a big gap between of potential savings, and that's the negotiable area that we are pursuing at the present time.

But BPA's recent price hikes have made the expansion of intertie capacity a more and more doubtful economic proposition for California when the costs of the intertie itself are factored in. Worse, because BPA has refused to adopt a cap or a long-run formula for its non-firm energy prices, we have no guarantee that BPA won't raise its prices even higher once the intertie is built.

We stand ready to approve the participation of California utilities in intertie expansions as soon as BPA can provide reasonable assurances that prices will remain at reasonable levels over the life of the expanded intertie. We hope to continue to work with BPA to realize the billions of dollars of savings that can accrue to the ratepayers of both regions.

So in summary, I should point out California's electric power supply prospects can be characterized as abundant well into the 1990's. Our major objective is to ensure that the supply options selected are the most cost effective and beneficial to ratepayers. The California Public Utilities Commission has embarked on a strategy combining market pricing and expanded regional cooperation in order to achieve this goal.

Thank you.

[The prepared statement of Mr. Vial follows:]

POTENTIAL FOR SERIOUS REGINAL SHORTAGES OF ELECTRIC POWER IN THE US BY THE EARLY 1990's

Testimony Prepared By

Commissioner Donald Vial, President
California Public Utilities Commission

For

The Senate Committee On Energy and National Resources

July 23, 1985

I am pleased to have this opportunity to address the issue of future electric power needs in the United States before your Committee. The key to gaining an insight into this issue is the recognition of regional diversity. The projections that I present of California's electric power needs may be different from those of New York, Illinois, Pennsylvania, Connecticut and other areas of the country represented here today. In addition, the California Public Utilities Commission's (CPUC) regulatory approach towards utility resource planning, which I will also describe, may differ from those used in other states.

Unlike most other states in the nation, California projects a strong "buyers market" for electric power well into the 1990's. In its 1985 California Electricity Report, the California Energy Commission (CEC) projects that we will need a total of 21,383 MW of resource additions capable of generating 40,458 GWh of electricity over the next 12 years. However, as illustrated in Figures 1-1 and 1-2 from that report, the array of identified projects in California exceeds the need for resource additions by a wide margin.

This represents quite a change from the electric power market facing us in the mid-1970's. In 1974, demand forecasts indicated that over 100 thousand MW of electricity would be needed by 1994, and California utilities anticipated building over 40 thousand MW of nuclear power plants in the state to meet that demand. By 1984, demand projections had been cut in half. This year, the CEC projects that, by the year 2004, conservation and load management programs in California have the potential to reduce peak demand by 14,000 MW, saving over 37,000 GWh in energy requirements.

On the supply side, California can probably satistfy a large part of its needs with surplus power from the Northwest and Southwest. According to the Energy Commission, California utilities are negotiating for the purchase of 1600 MW of capacity and 13,150 GWh of energy from utilities in the Pacific Northwest. Another 28,016 MW of energy could be available with increased conservation efforts in the Northwest, construction of new transmission capacity between the two regions, and/or sales by Canadian utilities. Enough energy is available from the Northwest alone to satisfy all of California's 40,000 GWh need.

We also expect to be able to buy large amounts of energy from the Southwest. California utilities are now negotiating for about 940 MW of capacity and 6702 GWh of energy from that region, and another 20,700 GWh may be available, amounting to more than half our total need.

Large amounts of power are also available from in-state sources--and mostly because of the rapid development of non-utility generating plants, a phenomenon which is probably the most significant change in the electric market on the supply side. Prior to 1978, electric energy was produced almost exclusively at utility-owned power plants. In that year, the Public Utility Regulatory Policies Act was enacted. The new law required that utilities purchase electrical energy offered to them at a price which was based on the cost they would have incurred absent the offered energy. The CPUC was charged with the mission of establishing these rates, which have become referred to as "avoided cost prices". Parties which met the conditions set forth in PURPA were termed "small power producers" or "qualifying facilities"--or what we have termed: "QFs".

Even in 1978, the potential for QF power was estimated to be quite large--but the rate of development of these technologies: cogeneration, solar, wind, biomass, geothermal, etc., was estimated to be slow. As recently as 1983, in its Fourch Biennial Report, the CEC estimated that about 7,000 MW of alternative energy projects would develop over the next twelve years.

However, as of the end of April, 1985, projects totaling over 13,000 MW had received signed contracts from California utilities and approximately another 8,000 are under consideration. While many of these projects may not develop and ultimately produce power, they illustrate the explosive growth in the QF industry and its emergence as a major energy resource.

As a result of actively pursuing conservation, load management and alternative technologies for electric generation, California now faces an abundance of supply alternatives well into the 1990's. In recognition of this fact, California utilties are not planning to build new large baseload plants in California for at least the next 8-10 years.

Unfortunately, accompanying this abundance of supply is a disturbing trend in the state's electricity prices. The California Electricity Report summarizes this trend as follows:

> "On average, California's electricity rates have more than doubled in the last 10 years. In particular, California's industrial electricity costs which were below the national average 10 years ago, are now 147 percent of that average. While industry has responded to this trend by improving the efficiency of their electricity consumption, high electricity prices have contributed to decisions to locate or relocate outside the state to avoid California's high electricity prices."
>
> "Fuel is the largest single component of electricity costs in California--37 percent of total cost. California fuel prices are higher than the rest of the nation because following the Mid-East oil crisis, California utilties were concerned that fuel supplies would be inadequate. As a result, they entered into long-term take-or-pay contracts at rates which included an insurance premium guaranteeing supply. Those contracts required utilities to pay fuel prices well above the current market price. In the 1950s and 1960s, an era of abundant cheap fuel, California utilties built a large part of our existing electricity supply system to rely on oil- and gas-fired generation. When the oil price spikes of the 1970s occurred, California responded by promoting conservation and alternative forms of energy as a means of displacing oil and gas. The 1970s taught us not to put all of our electricity supply eggs into one resource basket, but this lesson came too late to avoid the significant electricity rate hikes of the early 1980s. Not all of the dramatic increases in electricity costs are attributable to OPEC. Power plant construction cost overruns, time delays and increased nuclear-related health and safety regulations have also contributed." (page 6, The 1985 California Electricity Report, California Energy Commission, May 1985).

In addition, we are facing higher and higher rates for surplus power from the Bonneville Power Administration and other sellers in the Northwest. BPA has raised its rates for surplus power continuously over the past several years. Prices for power are now in many cases very close to what we would have to pay to generate our own power from natural gas. Furthermore, BPA has decided to exercise monopolistic control over the Intertie between to two regions, to prevent competition from driving prices down to more reasonable levels. California has thus been denied access to abundant and cheap hydro power available from British Columbia, all so BPA can protect its own higher prices.

Hence, the dilemma facing California for the remainder of this decade is to devise an energy policy which will result in more affordable and a more competitive level of electricity prices. As regulators, we need to insure that California only invests in cost-effective supply alternatives. We are faced with the task of selecting, among many different types of energy technologies and options (including purchased power, conservation and load management), those that benefit our ratepayers and the economy as a whole. At the same time, we need to create a regulatory environment that encourages the development of new and efficent energy technologies.

To achieve this, the CPUC has embarked on a regulatory strategy to use "pricing", to the extent practicable, as a mechanism for determining what should be built in California. In implementing PURPA, we recognized the value of establishing "benchmark prices", or what we call avoided costs, that a QF could automatically receive. These benchmark prices are designed to reflect the operating costs, shortage/or capacity costs that the utility avoids by having the QF sell its power to the grid. Under this approach, ratepayers reap the benefits of a diversified resource base and the longer run benefits of declining utility avoided costs, and also bear reduced risk of construction cost overruns and fuel price fluctuations.

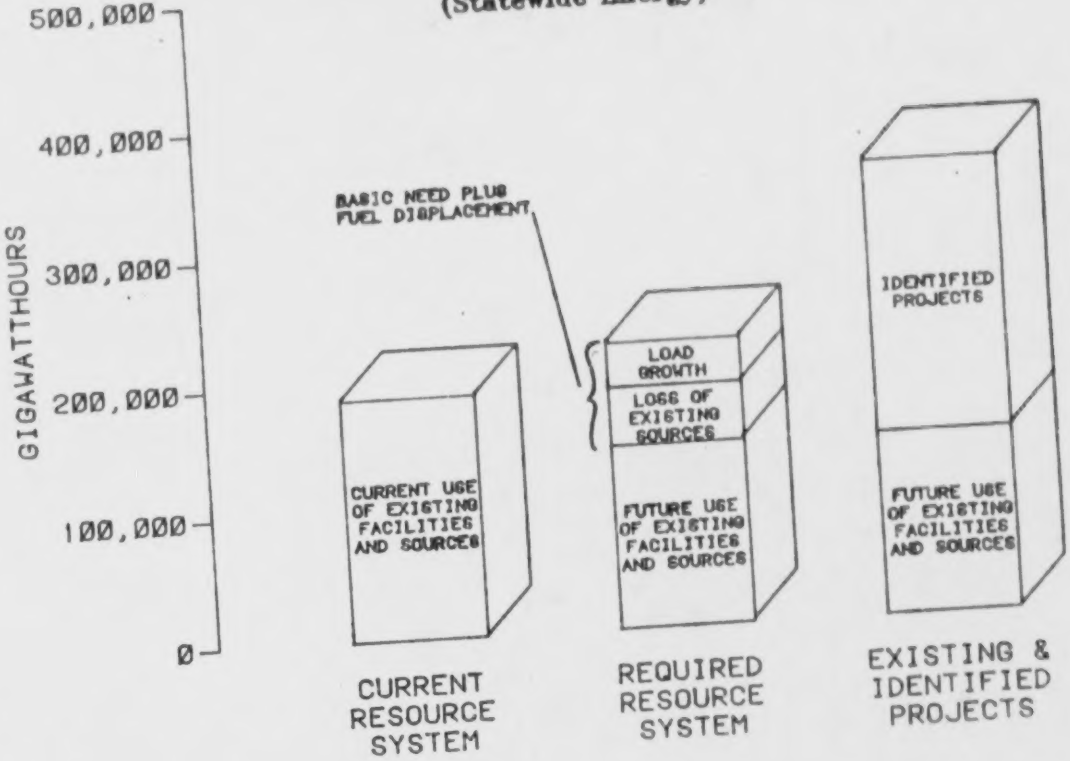
This approach is not just used for the QFs. Increasingly, the CPUC has chosen to review all utility generation projects and conservation budgets using the same pricing benchmark that we use for QF pricing. If, for example, a proposed utiltiy project is projected to be more expensive than the prices we would pay for small power producers, the PUC has been reluctant to approve the project, and has even recently considered avoided cost "caps" on rate recovery. The PUC has also rejected conservation proposals, for example, which did not appear to be cost-effective based on this test (and obviously vice versa).

In addition, the Commission has actively encouraged expanded cooperation with neighboring regions of the country. Expansion of intertie capacity between the Northwest and California, for example, could reduce the joint operating costs of both region's systems by literally billions of dollars over the coming years. This is because a price anywhere between BPA's production costs and below our avoided costs will share the benefits between the two regions. But BPA's recent price hikes have made the expansion of intertie capacity a more and more doubtful economic proposition for California, when the costs of the intertie itself are factored in. Worse, because BPA has refused to adopt a cap or a long-term formula for its non-firm energy prices, we have no guarantee that BPA won't raise its prices even higher once the intertie is built. We stand ready to approve the participation of California's utilities in intertie expansions as soon as BPA can provide reasonable assurance that prices will remain at reasonable levels over the life of the expanded intertie. We hope to continue to work with BPA to realize the billions of dollars of savings that can accrue to the ratepayers of both regions.

In sum, California's electric power supply prospects can be characterized as abundant well into the 1990's. Our major objective is to insure that the supply options selected are the most cost-effective and beneficial to ratepayers. The CPUC has embarked on a strategy combining market pricing and expanded regional cooperation in order to achieve this goal.

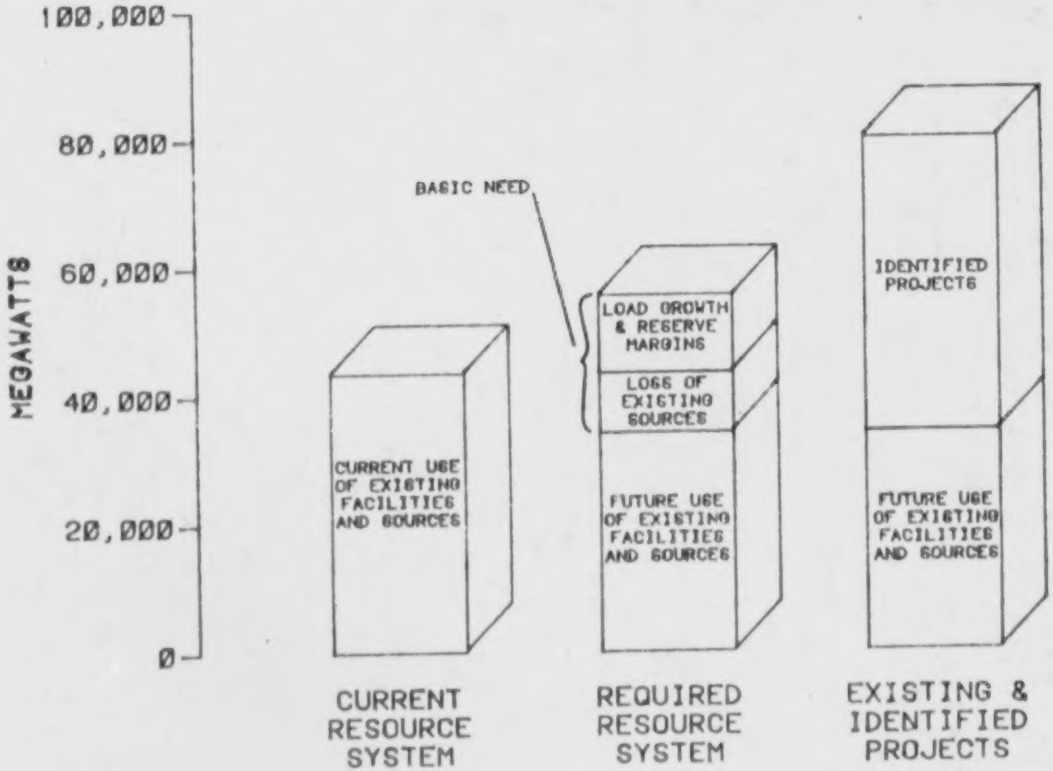
COMPARISON OF EXISTING SYSTEM, NEEDED ADDITIONS, AND IDENTIFIED PROJECTS

(Statewide Energy)



COMPARISON OF EXISTING SYSTEM, NEEDED ADDITIONS, AND IDENTIFIED PROJECTS

(Statewide Capacity)



The CHAIRMAN. Thank you very much.
Ms. Taliaferro.

STATEMENT OF LINDA C. TALIAFERRO, CHAIRMAN, PENNSYLVANIA PUBLIC UTILITY COMMISSION

Ms. TALIAFERRO. Thank you, Mr. Chairman. I have the opportunity to appear here and I'm going to use the Pennsylvania experience, although I'm not necessarily speaking for my entire commission. I do want to make that clear.

I have taken the approach of answering very specifically the questions asked by, forwarded to me by your assistant Mr. Doane. For example, on the minimalization policy, the bottom line is that we in Pennsylvania can clearly trace the fact that our electric generating stations that have been accepted for commercial operation during the past 2 years, 1983 to 1985, are the result of commission actions taken back in the period of 1965 to 1970.

I provide for you a history of the Northeast blackout and the Pennsylvania role, in combination with the commissions of Maryland, the District of Columbia, Virginia, and New York, as well as the utilities involved. I don't know whether that history has ever surfaced before, but our files provided the answer to it.

It showed how the 20 percent reserve margin was established and established and supported at the Federal level, which has become the rule of thumb for today. In any event, I won't reiterate that. I do provide that in the attachments.

As to whether serious shortages of base load generating capacity will occur on individual utility systems in the 1990's, we in Pennsylvania do not foresee that as a result of load growth. Our shortages that could occur or may occur would be the result of lower performance of existing generating stations, failure to finish base load stations under construction, or environmental regulations that limit the use of certain coal-fired stations.

We presently in Pennsylvania project and expect the load to increase at an annual average rate of approximately 3 percent or less, and capacity additions are under way to provide 5,000 megawatts of new generation, including Beaver Valley 2, Susquehanna Unit 2, Limerick 2. And I point out that Limerick is currently before our commission under extensive investigation and I will make no more comment on that issue.

I also point out the industrial load growth disintegration that occurred in Pennsylvania and the result during that period up to 1980. Our recovery has been slow, but we are faced now with the problem of recovering millions of dollars in investment in plant that has no new load to serve. We do not expect any shortages of capacity, as I indicated.

Even if we did, which is one of the questions, I point out that Pennsylvania's position as part of the Pennsylvania, New Jersey, Maryland interconnection, as well as our, to the west, membership in the East Central Area Reliability Coordination Agreement. With those two systems in place, I'm pointing out that Pennsylvania under the PJB has installed capacity of 48,025 megawatts and a projected load of but 35,000 megawatts, with a reserve of approximately 34.8 percent.

If we were to look to the west and the ECAR membership, their installed capacity is 79,000 or so megawatts, the projected load of 64,000 or so, leaving again a reserve, installed reserve of 22.8 percent, all of which points out we don't anticipate problems until well into the nineties, if at all.

We also still have the combustion turbines all coming in on line. I also provide in the attachments the basis for retiring such turbines and how the schedule comes to the commission for that process.

I also point out clearly, the alternative to interruptions in electric supply service in Pennsylvania is a commission strong commitment to well-designed conservation programs and incentives for scheduling energy usage in off-peak periods. I indicate the kinds of programs and commission policy statements since 1983 which have put those programs into effect.

I would also point out, we use rate structure as a mechanism of encouraging load management, time of day rates, demand rates, off-peak controlled service rates, offering discounts and/or penalties to induce changes in customer behavior patterns. We have found customer cooperation in conservation and we have seen that through our voluntary curtailment rate structures and the response of the customers who agree to curtail their load when notified by our utilities.

In particular, I heard much about TMI earlier sitting in the audience. I point out the Metropolitan Edison Co. and Pennsylvania Electric Co. have a vigorous conservation and load management effort after losing the Three Mile Island generating facility. Full implementation of their plan is expected to achieve a reduction in capacity needs of 1,000 megawatts, and we feel that's a very significant proportion and that other utilities could achieve the same types of results.

I also list the actual figures for 1984 conservation, cogeneration, and small-scale hydro, actual savings and forecasted savings.

I would like to go to the questions on, do the utilities have an incentive to minimize their investment in new central generating stations? The bottom line answer is yes, and I provide an explanation of our view as to why we think that way.

But I would also point out one point, and that is how Pennsylvania acts when it comes to the determination of excess capacity. It is not an arithmetic straightforward exercise. We look at formulas as being comforting and precise, but not flexible enough to account for the differences in conditions.

Utility regulation involves judgment and opens the possibility for some imprecise quantification of the facts developed in a rate proceeding. Ratemakers or regulators have become more responsive to changed economic, environmental, social, legal, and political situations. I think that is well and good.

The evaluations of past and present utility management decisions and the desire to affect future decisions have always been very fundamental to ratemaking. In Pennsylvania, we evaluate the existence of excess reserve margins of generating capacity for an individual utility's supply requirement. That's a very basic first question.

But once it's determined or if it's determined excess capacity exists, the more judgmental question is what do we do? Our evaluation of the unique facts of each situation now comes into play. If we were to review the past decisions of the Pennsylvania commission over the last several years, you'd see that in some instances we have made no adjustment or penalty because we believed the record demonstrated that the utility had been caught by rapid changes in economic conditions in the service territory.

Yet in other cases, you would see that the finding of the existence of excess capacity was pointed out as prudently planned for and constructed, yet a significant deduction to the utility's income was made in such a way as to encourage the sale of that capacity. In yet a further case, we balance the risk of the success of controlling energy costs with the expected equity return due to new generation, the new generating station.

In each case, there is a multitude of variables that affected our judgment as to what constituted a reasonable balancing of responsibilities. We looked at such things as the utility's supply mix, fuel costs, its planning and management criteria, its overall reputation for management effectiveness and responsiveness, the economic conditions of the service territory, its future short-term and long-term financial conditions, the existence of potential sales of energy, and the reasonable supply alternatives available to the company at the time.

And I could go on and on and on with that list. But each case is looked at very careful. I go on to further point out the factors that contribute to the incentives that the commission used.

But I also want to get particularly to question six, which is to what extent have so-called rate suppression decisions increased the risk of future shortages? And as a regulator, I have to say that is a "When did you stop beating your spouse" question.

The direct answer is, yes, there is a risk, but we find no way of quantifying the exact extent of the risk of future shortages of electric generating capacity triggered by so-called rate suppression decisions. And I'd have to define a rate suppression decision as that which artificially limits the amount of allowable returns from that which traditionally would have been found reasonable.

Let me suggest that for each so-called rate suppression decision there exists a regulatory body that grappled with real or perceived rate shock issues. In old-fashioned regulatory terms, rate shock would be violative of the tariff rate design principle of gradualism. Granted, this concept of gradualism is narrowly applied to individual rate designs, but where you ignore this concept and when each individual rate design is totaled up to a whole package for a utility, then rate shock is a very real possibility.

The rate increases necessary in my view today to allow a utility the opportunity to realize the level of profits once earned in the pre-sixties by them would violate that principle of gradualism across the board. I do not see an end, however—let's be fair on the other side of the coin—to the construction of large generating stations as being very near.

The utilities will need outside financing for such construction needs. The need will exist because there is in the short term no reason to forego the economics that large central stations present, and we do still recognize limitations of the alternative sources of supply that we have in place today.

But because there is a need, the financial community in my view will adapt and new and more acceptable investment and risk levels will be established. Utility management is adapting, and what's really going on in my view right now is the formation of a new set of expectations among all the institutions involved. We are undergoing changes in behavior—regulators, the utility management, the financial community.

And I would suggest to you, to the extent that we do not change, that State regulators are not responsive to signals that rate or price shock is occurring, I would ask you who or what other institution do we have that would initiate change as quickly as the State regulators can by pointing out the limitations of the policy today?

And finally, on the last issue of who should have the responsibility for electric power supply planning, I hesitate to admit being a lawyer after what I heard this morning; however, under the existing legal and economic structure of privately owned companies, I strongly believe that it should remain in the hands of the utility managers who are responsible to the companies 'owners.

I would not shift all responsibility into State, Federal regulatory commission hands. But my view is that the structure today conceptually is not the problem. It's the execution under the concept is where the problem is, and the responsibility and the accountability can be shared across many layers, privately and on the public side.

My suggested room for improvement would be to have a regionally based multi-State agency, and I know it sounds like creating another layer of bureaucracy, but having a regionally based multi-State agency created that would evaluate the need for construction of new central stations, the electric power supply planning issues, and the actual construction involved.

And I would suggest to you that existing multi-State compacts for water stewardship are in place and would provide the kind of model that could be used here. The body would review the joint planning decisions made by utilities involved in the construction. The body could consider the original need for the proposed facilities, monitor the ongoing construction, have periodic reviews made to factor any changed conditions, each member State then being represented.

If State regulatory responsibility were also retained, rather than removed—I share with you my personal view that the technology is making the boundaries of the State very much artificial. But if we still had a transition period of keeping State responsibility, but having this other body, you could have the State retaining authority to determine the appropriate rate levels and rate design to be allowed the utilities under their jurisdiction. They would be determining what their slice of the pie and how it should be allocated.

I think in this situation you have much less likely excess capacity problems. You could mitigate them on the economic dispatch basis. You would be limiting rate shock to relatively smaller shares based on ownership by many utilities.

I believe the costs of central generating stations are so great, their investment should be shared among a number of potential users who could receive short-term and long-term benefits. The sharing of the benefits and responsibilities should involve utilities in several States. The possibility to sell amounts of temporary excess energy or dispatch economic energy at a profit would help alleviate State local ratemaking pressures. I think it would also increase the reliability of energy supplies and offset short-term outages.

Thank you very much.

[The prepared statement of Ms. Taliaferro follows:]

STATEMENT OF
THE HONORABLE LINDA C. TALIAFERRO
CHAIRMAN, PENNSYLVANIA PUBLIC UTILITY COMMISSION

BEFORE THE
UNITED STATES SENATE
COMMITTEE ON ENERGY AND NATURAL RESOURCES

JULY 23, 1985
WASHINGTON, D. C.

Good afternoon Mr. Chairman and distinguished members of this Committee on Energy and Natural Resources. I am Linda C. Taliaferro, Chairman of the Pennsylvania Public Utility Commission. I am pleased to have the opportunity, with other regulators, to appear before you as you begin your inquiry on the potentiality for regional shortages of base load generating capacity by the early 1990's.

By earlier correspondence and discussion with Mr. Doan of this Committee's Staff, the focus of these hearings has been made clear, namely your emphasis is placed on examining forecasts of electric power supply and demand, a concern with whether our electric utilities are being compelled to pursue a "capital minimization" policy, as well as seven other questions, as follows:

1. Will serious shortages of baseload generating capacity occur on individual utility systems by the early 1990's?
2. If such shortages occur, would each utility faced with such a shortage be able to prevent actual interruptions in service by obtaining additional supplies, such as combustion turbine generation of purchased power?
3. In your forecast of electric power supply, what are the assumptions relating to the retirement schedule for existing generating plants?
4. Do electric utilities have an incentive to minimize their investment in new central station generating stations?

5. If so, what are the factors contributing to the incentives?
6. To what extent have so-called "rate suppression" decisions by some state public utility commissions increased the risk of future shortages of electric generating capacity?
7. Who should have the responsibility for electric power supply planning, electric utilities or state regulatory commissions?

My following testimony today based upon my Pennsylvania experience and is directly in response to these specific questions as fully as it is appropriate for me to do so within existing legal restraints and mandates imposed by my Commonwealth's rules and regulations.

ARE ELECTRIC UTILITIES TODAY BEING COMPELLED TO PURSUE A "CAPITAL MINIMIZATION" POLICY?

Let me begin by stating that the Pennsylvania Commission has not by its recent action in rate cases and special investigations established a policy of "capital minimization" for electric utilities. We are, however, exercising our power of regulatory surveillance over utility investments in new plant to determine whether or not utilities have acted prudently and in the interests of their customers. Electric generating stations that have been accepted for commercial operation during the past two years are the result of the Commission's action from 1965 through 1970. Unprecedented load growth during that same 1965-70 period exceeded the electric utilities generating capacity and required many utilities to rely on bulk power purchases from the transmission line interconnection system.

The series of blackouts and brownouts that followed the Northeast blackout on November 9, 1965, were the result of poor load forecasting procedures and disregard of protective measures to prevent the effects of one utility's problems from interfering with neighboring utilities' operations. The Pennsylvania Commission recognized that the interconnected utilities and their regulatory commissions were not communicating with each other and the situation would become progressively worse. The Commission, therefore, arranged joint meetings with the Commissions of New Jersey, Maryland, Delaware, and the District of Columbia. Similar meetings were held separately with the New York Commission and Federal Power Commission. Dates of meetings are described in Attachment A.

The purpose of those urgent meetings was to determine the contingency plans necessary to prevent a recurrence of the Northeast blackout. After the Commissions concluded their executive sessions, the electric utilities were invited to join the Commissions in open sessions to explain their construction programs and load shedding procedures.

Concurrent with these meetings, operating problems that we feared were actually occurring. Pennsylvania and its neighboring states in the East had 16 brownouts in 1969 and 17 in 1970. Numerous local blackouts occurred which interrupted service to industry, commerce, and dwellings. The operating reserve capacity in the PJM Interconnection was reduced to less than 3% during peak loads and transmission lines were loaded to maximum capacity. Attachment B describes a typical situation and shows the most recent PJM report.

The situation was desperate enough for the Pennsylvania Commission to call a meeting of commissions and utilities involved with the PJM Interconnection. The consensus of opinion was that the utilities must immediately install 2,000 megawatts of combustion turbines to serve the load that had developed without detection by utility forecasts. The utilities contacted vendors and informed the commissions that only 1,200 megawatts of turbine capacity was readily available. The commissions accepted the report and told the utilities to install the equipment immediately and if emergency rate relief was necessary, we would conduct hearings on an expedited basis. On June 5, 1967, the blackout that we feared actually occurred and affected the four states and District of Columbia served by PJM. If the turbines had been installed, the blackout would not have been as prolonged or severe.

The utilities were also told that a 20% reserve margin was not unreasonable and new capacity addition should be started immediately. Numerous meetings with the Federal Power Commission resulted in a 20% reserve margin being adopted on a national level.

The Pennsylvania Commission internally adopted emergency regulations to deal with capacity shortages, fuel interruptions, and power plant shutdowns. Emergency Electric Regulations Dockets 1, 2, 3 and PRMD 9 are attached (Attachment C). We also required the utilities to file with us load control procedures and priority lists of critical customers. These orders and policy are still in effect and recognized by the current Commission as essential to the health and economic strength of our state.

Because of this pioneer work we do not anticipate any serious shortages of baseload generating capacity in individual utility systems by the early 1990's as the result of load growth.

1. WILL SERIOUS SHORTAGES OF BASELOAD GENERATING CAPACITY OCCUR ON INDIVIDUAL UTILITY SYSTEMS BY THE EARLY 1990's?

It does not appear that shortages of baseload generating capacity will occur by the early 1990's as a result of load growth. Shortages may occur as the result of lower performance of existing generating stations, failure to finish baseload stations under construction or environmental regulations that will limit the use of certain coal-fired stations. The Commission's technical staff has prepared, at my direction, a capacity-load-reserve forecast for each electric utility in Pennsylvania and also the extent of their participation in electric power tools.

The forecast is assembled into a single report that discusses in detail the current condition of seven major electric utilities that generate, transmit, and distribute power. Attachment D shows the statistics for those utilities. It also shows the load growth and capacity additions by fuel source for the next ten years. We presently expect load to increase at an annual average rate of approximately 3% or less and capacity additions underway to provide 5,000 MWs of new generation, including Beaver Valley 2, 833 MW; Susquehanna 2, 1050 MW, and Limerick 2, 1055 MW. Limerick is currently the subject of Commission investigation and further discussion by me is inappropriate.

The industrial electric load of Pennsylvania has traditionally used 50% of generating capacity during peak hours. The economic conditions that started to decline in 1974 depressed Pennsylvania's industry as much or more than other states.

This is clearly seen by comparing Pennsylvania's economic growth from 1974-1983 to that of the U. S. During this period, the U. S. experienced an annual growth rate in real Gross National Product (GNP) of 2.34 percent. Meanwhile, Pennsylvania experienced an annual growth rate in real Gross State Product (GSP) of only 0.13 percent. The depression in Pennsylvania's manufacturing sector is manifested by the trend in industrial electricity sales over this same 1974-83 period. During this time, industrial electricity sales in Pennsylvania have decreased at an annual rate of 0.96 percent. In 1974, industrial sales comprised 50 percent of total electricity sales in Pennsylvania. Presently, they are only about 42 percent of total electricity sales or a reduction of 8%. (Attachment D-1).

Recovery has been slow and industrial electric load, once forecasted to increase significantly, has not developed as expected. Residential load was increasing at an annual rate in excess of 9% for eight years prior to the oil embargo. As a consequence, construction of new electric generating stations was started to prepare for the forecasted load growth.

The generating units recently completed Beaver Valley 1, 810 MW; Susquehanna 1, 1050 MW, and Limerick 1, 1055 MW were scheduled to supply the demand that was not developed. Pennsylvania electric utilities are now faced with a problem about how to recover millions of dollars in investment in plant that has no new load to serve. We do not expect any shortages of capacity to serve load by the early 1990's because of this situation.

2. IF SUCH SHORTAGES OCCUR, WOULD EACH UTILITY FACED WITH SUCH A SHORTAGE BE ABLE TO PREVENT ACTUAL INTERRUPTIONS IN SERVICE BY OBTAINING ADDITIONAL SUPPLIES, SUCH AS COMBUSTION TURBINE GENERATION OF PURCHASED POWER?

Pennsylvania does not expect any shortages; however, if load increases beyond the ability of internal generating capabilities the electric utilities have the resources of two very important interconnection systems to purchase power. The Pennsylvania-New Jersey-Maryland (PJM) Interconnection is a summer peaking central dispatch system that has five member utilities from Pennsylvania. Its installed capacity is 48,025 MW and projected load of 35,610 MW. Installed reserve is 12,415 MW or 34.8%. The East Central Area Reliability Coordination Agreement (ECAR) is a system of information distribution which allows member utilities to negotiate their own sales and purchases. Three member utilities are from Pennsylvania. ECAR members have installed capacity of 79,626 MW and projected load of 64,819 MW. Installed reserve is 14,807 MW or 22.8%.

Pennsylvania is in a unique geographic position for transmission line interconnections between electric regions in the Northeast section of the nation. The electricity being supplied to Washington, D. C. by Potomac Electric Power Company (PEPCO) could conceivably be generated in Pennsylvania because PEPCO is a member of the PJM Interconnection headquartered in Pennsylvania. Electric Energy is transmitted from the central generating stations to the high voltage distribution systems of the utilities and eventually to their customers. Excess capacity produced by those central stations is available on the interconnection system for sale to other electric utilities who either have a generation deficiency or cannot generate power at a rate lower than they can purchase power. This ability to purchase power and the need to improve reliability is responsible for a very strong transmission line network. Attachment E shows the import/export capability of the National Electric Reliability Council (NERC) member systems. It appears that there is sufficient energy available through the early 1990's to supply individual short term energy needs from the transmission interconnection system. Transmission lines, however, are not considered a solution to long term power needs of utilities that may encounter capacity needs. Transmission lines are very vulnerable to climatic conditions such as the recent tornados that struck northwestern Pennsylvania in June of this year. Although this devastation was concentrated in one region, it did not affect the electric needs of another region because no major transmission lines were destroyed. The possibility exists, however, that the storm would have struck major lines if it were a few miles either north or south of its path.

Combusion turbines are a short term solution to a long term problem. Pennsylvania electric utilities have 103 turbines with a combined capacity of 2,756 MW. The cost of generating power by either oil or natural gas in a turbine engine is both expensive and inefficient. Residential customers could not afford electricity generated by turbines because the fuel costs would eventually be a burden passed along to all classes of customers. There is no non-discriminatory mechanism available to insulate customers by class from sharing the cost of generation. The residential customers will share the high cost of generation which amounted to 13.5¢/KWH compared to 2.4¢/KWH for coal-steam units and 2.0¢/KWH for nuclear steam units.

Moreover, the alternative to interruptions in electric supply service in Pennsylvania in the event of supply shortage is a well designed conservation program and incentives for scheduling energy usage to off-peak periods.

On August 19, 1983, the Commission adopted a policy statement on electric utility financing of energy supply alternatives, whereby regulatory incentives would be afforded to any cost effective conservation inducing investment designed to lower a utility's need to install additional capacity. These regulatory incentives, in the form of rate treatment procedures, will allow utilities to recover all reasonable costs associated with the development, management and operation of energy supply alternatives such as conservation, load management, and alternate energy supply projects.

During 1984, electric utilities expended over $23 million for conservation and load management programs which resulted in an estimated on-peak reduction of 240,158 kilowatts and a savings of 435 million kilowatt-hours. This expenditure amounts to under $100 per kilowatt reduction.

Collectively, the electric utilities administer about 125 programs which include informational activities, time-of-day rates and appliance rebates. Many of these programs are designed to encourage customers to manage their electrical load by reducing consumption during on-peak periods and by shifting load to off-peak periods. Various incentives are used to induce this activity.

Rate structure is by far the most widely utilized mechanism for encouraging load management. Time-of-day rates, demand rates, off-peak controlled service rates offer discounts and/or penalties to induce changes in customers' consumptive behavior patterns. The dissemination of information on energy efficiency and the offering of rebates on selected high efficiency appliance are other examples of utilities' efforts to reduce peak load growth and thereby minimize their investment in a new plant. A description of these programs is attached. (Attachment E-1)

The concurrent use of electric energy by all classes of customers is responsible for system peaks. If incentives are offered to customers for management of their load then the peak load is modified to a shoulder load. The difference between the two loads is that the utilities have an opportunity to schedule generation over a longer period of hours instead of running equipment at maximum capacity for a short period. The result is lower incidence of equipment failure, lower fuel costs, and more opportunities to purchase replacement power.

Customer cooperation in conservation has proven to be a viable alternative to short term supply needs. This has been demonstrated in the past during short term operating capacity shortages when public appeals for reduced consumption of electricity resulted in substantial reductions in system peak demands, thus eliminating the need for mandatory reductions or elimination of power use and reduction of hours of operation. Voluntary curtailment rate structures are also effective in reducing peak demands by offering incentives to customers who agree to curtail a portion of their load when notified by utility personnel.

Metropolitan Edison Company and Pennsylvania Electric Company embarked on a vigorous conservation and load management effort after losing the use of their generation facilities at Three Mile Island in 1979. Full implementation of their aggressive plan is expected to achieve a reduction in capacity needs of 1000 MW. Other utilities could begin now, regardless of their current capacity supply situation, to reduce demand growth and delay the need for costly new plant through investment in alternate energy supply programs. The following table illustrates what has been accomplished by conservation measures to reduce electric energy needs and also the contribution of alternate energy sources to supplement utility supplied power.

1984

Conservation (MW)		Cogeneration (MW)		Small Scale Hydro (MW)	
Actual	Forecasted	Actual	Forecasted	Actual	Forecasted
240	230	501.5	428.7	440	625

3. IN YOUR FORECAST OF ELECTRIC POWER SUPPLY, WHAT ARE THE ASSUMPTIONS RELATING TO THE RETIREMENT SCHEDULE FOR EXISTING GENERATING PLANTS?

In Pennsylvania we adopted investigation Docket 138, Attachment F. The electric utilities are required to annually report their current and forecasted operating conditions including planned retirement of existing generating facilities in consideration of various factors, such as load growth, economics, technology, environmental concerns and the physical condition of the units. A typical report is included with Attachment F. Completion and operation of new generating units to replace those reaching their useful lives is also a major concern of each utility.

Most units targeted for retirement are small oil-fired steam units, installed 35 or more years ago, and oil-fired combustion turbines. In many cases it is less costly to purchase power from the interconnection, or from another utility, than to generate power from these units.

Over the years, utilities have sustantially revised their plant retirement schedules due, in most part, to the continually escalating costs of new construction. Many utilities have postponed plant retirements and have embarked on a life extension program which provides refurbishing and maintenance necessary to extend plant life 15 to 20 years beyond the normal 35 years. Currently, scheduled retirements amount of 1857 MW of oil-fired capacity through 1995 including 630 MW of combustion turbine capacity. These are either peaking or intermediate generating units.

In Pennsylvania, utilities must petition for and obtain the Commission's consent to remove generating facilities from normal operation. (Emergency Electric Regulation Docket No. 1, Attachment C.) During these proceedings, the Commission examines the impact the retirement will have upon the utility's ability to meet its customer demand. Recently, the Commission has emphasized the economics of plant retirements by determing whether it will be more cost effective for the utility's ratepayers if the unit were to continue normal operation rather than be replaced by a new facility or additional power purchases. Our overall concern is to insure that an adequate and reliable supply of energy is maintained at a reasonable cost to the ratepayers.

4. DO ELECTRIC UTILITIES HAVE AN INCENTIVE TO MINIMIZE THEIR INVESTMENT IN NEW CENTRAL GENERATING STATIONS?

The direct answer is yes. There are many incentives to minimize such investments. There is an often repeated so-called truism held by many that utilities love to invest, they love to build, because their profit depends upon the total amount of their investment. Like most widely held theories, there is a grain of truth here. The level of profits is determined for "ratemaking" purposes, by the level of investment. But, what is not a widely known or appreciated fact is that these "profits" are not guaranteed, nor are profits allowed on the vast amount of funds invested in property which is not "used and/or useful". For such property, regulators allow the recording of an Allowance for Funds Used During Construction, which is often called "funny money" by the investment community because it looks like a "profit" on an income statement but because it is not cash, you cannot pay an expense or a dividend out of this "profit".

The incentive to minimize construction does run directly counter to the ingrained engineering driven philosophy that a utility should be ready at all times and under all conditions to meet its "duty" to provide the energy demanded by the customer. There is, or there was, a very strong belief expressed often to me by upper utility management that we have to build generating facilities in order to fulfill our "duty" to serve the customer. Management is beginning to see, however, that the duty to serve can be met in ways other than simply adding more construction of large central generating facilities. The combination of various technological options available in addition to building large central generating facilities has just been written in the past decade. All options, however, must be viewed with a critical eye to the allocation of cost among the various benefactors. There are other ways today which can be used to meet the duty of providing service to ratepayers other than sole reliance on construction of new central-station generating stations.

My personal observation, as a regulator of six years' experience is that a Commission's determinations on excess capacity are not straightforward arithmetic exercises. Formulas, while comforting and precise, are simply not flexible enough to account for differences in conditions. Utility regulation involves judgment and thereby opens the possibilities for some rather imprecise quantification of the facts developed in a rate proceeding. Ratemakers have become more responsive to changed economic, environmental, social, legal and political situations. Evaluations of past and present utility management decisions and the desire to affect future decisions have always been basic to rate regulation.

The basic pattern in Pennsylvania has been to evaluate the existence of excess reserve margins of generating capacity for an individual utility's supply requirements. Thus, our first question is a relatively basic question. If it is determined that excess capacity exists, the more judgmental question is, what should the Commission do? Our evaluation of the unique facts of each situation now comes moreso into play for this question. A review of past decisions reveals that in some instances we have made no adjustment or penalty because the utility had been caught by rapid changes in the economic conditions of their service territory. In another case the existence of the excess capacity which was prudently planned and constructed yet made a significant deduction to a utility's income in such a way as to encourage the sale of that capacity. In yet another case, we balanced the risks of the success of controlling energy costs with the expected equity upturn due to a new generating station.

In each case differences in a multitude of variables affected the Commission's judgment about what constituted a reasonable balancing of responsibilities such as evaluations of the utility's supply mix and fuel costs; its planning and management criteria; its overall reputation for management effectiveness and responsiveness; the economic conditions of its service territory; its future short-term and long-term financial condition; the existence of potential sales of energy and the reasonable supply alternatives available to the company at the time, not to mention many others.

5. IF SO, WHAT ARE THE FACTORS CONTRIBUTING TO THE INCENTIVES?

There are many factors, such as:

A. The need to stabilize the company's financial status and minimize pressures on earnings and dividends;

B. The presence of capacity, either actually or potentially available;

C. Political, environmental or social pressures to curb rate requests, offer stable energy prices, hold off on installation of stations within their service territory which no matter of what type will have environmental problems, and the desire to hold off commitment to an existing type of generation until newer technology can be applied.

On the issue of stabilizing a company's financial status and minimizing pressures on earnings and dividends, and, putting aside the old maxim about financial success which states "Get the cash! Get the cash!! Get the cash!!!," construction of new central generating stations takes a lot of time and, of course, money. Utilities are often hard pressed to meet the tasks of managing such long-term, large-scale complex projects. Because these projects take so long, cost so much and are not generally, while under construction, allowed to be factored into the company's rate base for ratemaking purposes, they are drains on the company's cash resources, financing capabilities and earning potential. A company is open to much risk or actual damage to their earnings.

Although "risk takers" and financial speculators may enjoy the investment opportunities such utility construction projects now offer, for those who have been the backbone of utility investments, namely the large institutional investors and the "widows and orphans" who desired stable dividends with little risk, these investors are not receptive to absorbing cancelled plant costs or "phase-in plans". Today's wise manager has an incentive to curtail his construction requirements in order to keep such investors content. Such a manager desires to limit his "funny money" AFUDC earnings, as well as limit the pressure on his debt coverage ratio in order to keep the price of his company's common stock high and limit his interest costs on debt financing.

On the issue of the presence of capacity, either actually or potentially available, utility management is now aware that regulatory commissions believe that other sources of generation or supply are reasonable or desirable alternatives to new central stations. The potential exists that these sources may not be as expensive (See Question 2). Certainly, in terms of the total outlay of funds and the pressure of large scale financing required for large generating stations, these supply alternatives require less utility capital. It must be recognized, however, that the electric utilities must provide the reserve margin in the event the alternative supplies are unexpectedly not available.

Conservation investment, energy saving or load reduction equipment investment and cogeneration supplies are all being examined because they may make additional energy available. Utilities are being encouraged to investigate the full potential of these before turning to more traditional supply sources.

Finally, as to part "C" listed on page 16, over the last decade public utility regulators have faced some tough questions. The construction era of the past decade represents an era during which plants were planned based on certain assumptions about growth in energy demand, and expected construction costs and time frames. No matter how well-intentioned, prudent or logical those assumptions may have been, they really missed the mark. In today's age of cynicism, these prior predictions have taken on a meaning of their own. They serve as prima facia evidence that supports making any and all predictions about the future suspect.

Alfred E. Kahn has said that there is an implicit bargain between utility companies and government which lies at the heart of public utility regulation, and without which, regulation cannot function in the long-run. This bargain promises the companies the opportunity to earn a reasonable return--and no more--on all dollars prudently expended. Mr. Kahn noted that "you can't play a game of heads we win, tails you lose, with these companies and not pay for it the next time they go out to raise the capital they need to serve your constituents."[1]

In Pennsylvania we have used a two-part test to evaluate excess generating capacity. We examine the prudency of the construction decisions when they were made, and the used and useful status of the plant when rates will be in effect. Our focus regarding the useful status of a facility has been the reserve capacity ratio but the rate treatment for capacity found to be excessive has been tempered by the economic consequences of the plant operation based upon the Commissioners' individual and collective evaluation of what would constitute a reasonable sharing of the costs and benefits involved. This new focus on the issue of excess capacity obviously is a factor contributing to the alleged utility management's incentive not to commit to future central station generating capacity.

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[1] "The States and Utility Regulation, An Address to The National Conference of State Legislatures, New Orleans, Louisiana, November, 1984."

6. TO WHAT EXTENT HAVE SO-CALLED "RATE SUPPRESSION" DECISIONS BY SOME STATE PUBLIC UTILITY COMMISSIONS INCREASED THE RISK OF FUTURE SHORTAGES OF ELECTRIC GENERATING CAPACITY?

To a regulator this is a "when did you stop beating your spouse" question. The direct answer is "Yes", there is a risk. However, there is no way of quantifying the exact extent of the risk of future shortages of electric generating capacity triggered by so-called rate suppression decisions, (which I define as regulatory decisions that artificially limit the amount of allowable revenues from that which traditionally would be found reasonable) nor does this risk lack for a remedy. Let me suggest that for each so-called "rate suppressive" decision, there exists a regulatory body that grappled with real or perceived "rate shock" issues. In old fashioned regulatory terms, "rate shock" would be violative of the tariff rate design principle of "gradualism". Granted, this concept is narrowly applied to individual rate designs, but where this concept is ignored, when such individual rate designs are totalled up into a whole for a utility, then "rate shock" is a real possibility. The rate increases necessary today to allow a utility the opportunity to realize the level of profits once earned by them would violate the principle of gradualism across the board.

Nevertheless, I do not see the end of the construction of large generating stations as near at hand, and utilities will need outside financing for such construction needs. A need will exist because there is in the short-term no reason to forego the economics that large central stations present and there are recognized limitations in those alternative sources that exist today. Because the need, therefore, exists, the financial community will adapt, and new and more acceptable investment and risk levels will be established. The utility management is also adapting and what really is being reflected is the forming of a new set of expectations among all institutions involved. Therefore, we are undergoing changes in behavior by all, namely the regulators, the utility managements and the financial community. Moreover, to the extent that such change is not forthcoming (i.e., frankly if state regulators were not responsive to signals that "rate or price shock" was occurring), who or what established institution is there that would initiate change as quickly in a basically non-competitive environment?

7. WHO SHOULD HAVE THE RESPONSIBILITY FOR ELECTRIC POWER SUPPLY PLANNING, ELECTRIC UTILITIES OR STATE REGULATORY COMMISSIONS?

Again, my view is that under the existing institutional, legal, and economic structure today, for privately owned utilities, the responsibility for power supply planning should, and most efficiently and effectively, reside with electric utility's management who is responsible to the company's owners. I do not think it wise to shift all planning responsibility into state or federal regulatory commission hands. The structure today conceptually is not so much the problem as is the execution of tasks under the concept.

Nevertheless, there is room for improvement in my view, if a regionally based multistate agency were created which could evaluate the need for the construction of new central generating stations, and evaluate electric power supply planning. Existing multistate compacts for the stewardship of water resources serve as a guide on this point.

Such a regional body would review the joint planning decisions made by the utilities involved in construction or power pooling. The body would consider the original need for the proposed facilities and monitor the ongoing construction. Periodic reviews would be made to factor in any changed conditions which impact on the need for the facility. Each member state would be represented,

If state regulatory responsibility were also retained rather than removed, then each state's rate regulatory agency would retain its authority to determine the appropriate rate levels and rate design to be allowed the utilities under their jurisdiction. It would be much less likely that "excess capacity" would exist or could not be mitigated by sale on an economic dispatch basis--"rate shock" would be limited by the relatively smaller shares of ownership involved.

I also believe that the costs of central generating stations are so great that their investment should be shared among a number of potential users who could receive short-term and long-term benefits. This could lessen the financial pressures on the individual utilities involved and also lessen the magnitude of the rate increase necessary to allow an opportunity to earn a reasonable profit on the investment. The sharing of the benefits and responsibilities of these new stations will probably involve utilities in several differnt states. In addition, the possibilities to sell amounts of temporary excess energy or dispatch economic energy at a profit, could also help alleviate the ratemaking pressure. Such power pooling could also aid in increasing the reliability of the energy supplies and offset short-term outages.

Meetings and Reports

1) The Commission communicated with electric utilities in Pennsylvania following the northeast blackout of November 9, 1965 and requested on December 6, 1965 that reports be submitted explaining the present and future electric power supply situation within each company's operating territory and participation in power pools.

2) Subsequent to the Commission's review of these reports an invitation was extended on February 14, 1966 to all Pennsylvania companies to attend a meeting in Harrisburg on March 3, 1966.

3) On March 31, 1966 a joint meeting was held in Philadelphia with the commissions of New Jersey, Delaware, Maryland and District of Columbia to review the operation of the PJM Interconnection.

4) In April 1967, the Commission met with PJM representatives in Harrisburg to discuss the capacity-load-reserve forecasted for the summer of 1967.

5) A meeting was held on June 19, 1967 in Philadelphia with the other state commissions and PJM to review the June 5, 1967 PJM interruption. At this meeting the topic of automatic load shedding devices was brought up.

6) A joint meeting was held in Philadelphia on October 6, 1967 with Commonwealth Associates to study PJM. A contract was signed with Commonwealth in February 1968.

7) On April 30, 1968 the Commission again met with all Pennsylvania electric companies in Harrisburg to review the capacity-load-reserve forecast and load shedding facilities operable and planned.

8) On September 16, 1969 the Commission again met jointly with other commissions and electric companies to request the installation of peaking units to avert the expected generation deficiency in 1970 and 1971. We also wanted to discuss the results of Commonwealth Associates study of PJM.

9) On December 23, 1969 a joint meeting was held in Philadelphia with PJM to review the results of our studies which show that the companies will be faced with a serious deficiency in generating capacity if the load growth proceeds at a 10% annual figure. Companies agreed and committed $100 million in peaking power.

10) On February 16, 1970 a joint meeting was held between the PJM state commissions and the Federal Power Commission in Washington, D. C.

11) On November 10, 1970 a meeting was held in Philadelphia with companies and commissions.

12) On December 8, 1971 the Commissions met in the Holiday Inn, King of Prussia, and then met with the companies in the PJM Interconnection Center.

From December 6, 1965 to December 8, 1971 we met with Pennsylvania utilities and PJM untilties on twelve (12) separate occasions. During this same period nine (9) meetings included the three other state commissions and the District of Columbia.

There have been innumerable meetings on a committee level with both the electric companies and state commissions to discuss criteria, planning, and forecasting procedures.

PJM REPORT ON OPERATIONS

DATE Tuesday, September 22, 1970

WEEK ENDING September 25, 1970

PEAK LOAD 22,593 MW

HOUR ENDING 3:00 P.M.

SHEET 1 OF 5

INSTALLED CAPACITY 28,466 MW

INSTALLED RESERVE 5,873 MW 26.0 %

CAPACITY NOT AVAILABLE 7,598 MW

AVAILABLE RESERVE -1,725 MW -7.6 %

Forced outage 4,922 MW(1)

Scheduled maintenance 1,901 MW

Interim reduction 775 MW

VOLTAGE REDUCTION	FROM	TO
3% all systems	10:16 A.M.	10:22 A.M.
5% all systems	10:22 A.M.	10:59 P.M.

LOAD CURTAILMENT	FROM	TO
Non-essential utility building load	10:42 A.M.	10:59 P.M.
Maximum voluntary		
Pre-arranged	11:12 A.M.	9:59 P.M.
Radio & TV appeal	2:40 P.M.	9:59 P.M.
Manual		
500 MW (after loss of Keystone #2)	2:38 P.M.	(a)
Add'l 500 MW (after loss of Brunner Island #3)	4:44 P.M.	(b)
250 MW	7:30 P.M.	(c)
Add'l 250 MW	7:49 P.M.	(c)

(a) Load was restored as promptly as system conditions permitted: 100 MW at 3:05 P.M. and another 100 MW at 3:16 P.M. This load was again curtailed at 3:48 P.M. to maintain a reliable system operation. Restoration was completed between 5:23 P.M. and 6:00 P.M.

(b) Load was restored as promptly as system conditions permitted between 5:23 P.M. and 6:00 P.M.

(c) Load was restored as promptly as system conditions permitted: 200 MW at 8:03 P.M., 100 MW at 8:21 P.M. and 200 MW at 8:54 P.M.

PJM REPORT ON OPERATIONS, CON'T - TUESDAY, SEPTEMBER 22, 1970 SHEET 2

(1) MAJOR UNITS FORCED OUT

UNIT	MW	DATE OFF	DUE BACK	REASON
Keystone #1	820	7-11-70	4-1-71	Repair damage resulting from boiler explosion
Sewaren #5	344	9-2-70	11-1-70	Repair fire damage
Homer City #2	329	9-12-70	9-23-70	turbine valve adjustments
Chalk Pt. #2	165 (Redn)	9-21-70	N.A.	Boiler feed pump thrust bearing
Bergen #2	276	9-21-70	9-23-70	Water wall tube leak
Linden #2	110 (Redn)	9-19-70	9-27-70	Feed water heater leak
Martins Creek #1	148	9-22-70	9-23-70	Tube leak
Oyster Creek #1	530	9-22-70	N.A.	Repair steam by-pass valve
Keystone #2	820	9-22-70	9-24-70	Repair brush rigging
At 4:44 P.M.				
Brunner Isl. #3	730	9-22-70	9-23-70	Mill explosion

Remarks

Unseasonably high temperatures and exceptionally high incidence of forced outages made the voltage reduction and voluntary customer load curtailment necessary to maintain a reliable power supply. With the loss of Keystone #2 Unit at 2:29 P.M., it became necessary to order 500 MW of manual load shedding.

At 2:51 P.M. an appeal for customer co-operation was issued via radio and television. This appeal continued until 9:59 P.M.

At 4:44 P.M., Brunner Island #3 (730 MW energy) was lost and the amount of manual load shedding was increased by 500 MW. At 6:00 P.M. all manually-shed load was restored. Starting at 7:30 P.M., the evening load increase required manual shedding which totalled 500 MW by 7:49 P.M. This 500 MW was completely restored at 8:54 P.M. At all times, energy imports were scheduled to the limits of availability and transmission capability.

The following tabulation shows pertinent instantaneous values at critical points of operation.

	2:20 P.M.	2:45 P.M.	4:50 P.M.	8:00 P.M.
Installed Capacity	28,466	28,466	28,466	28,466
Capacity Not Available	6,778	7,598	8,328	8,328
Available Capacity	21,688	20,868	20,138	20,138
Load (instantaneous)	22,600	22,400	21,500	21,850
Available Reserve	-912	-1,532	-1,362	-1,712
Power Interchange with Other Pools & Systems				
PJM Received	1,770	2,020	1,740	2,370
PJM Delivered	300	200	200	200

INTERCONNECTION OFFICE

LDD 9-23-70

PJM REPORT ON OPERATIONS

DATE Wednesday, September 23, 1970 WEEK ENDING September 25, 1970

PEAK LOAD 22,644 MW

SHEET 3

HOUR ENDING 5:00 P.M.

INSTALLED CAPACITY 28,466 MW

INSTALLED RESERVE 5,822 MW 25.7 %

CAPACITY NOT AVAILABLE 7,134 MW

AVAILABLE RESERVE -1,132 MW -5.0 %

Forced outage 4,876 MW(1)

Scheduled maintenance 1,709 MW

Interim reduction 549 MW

POWER INTERCHANGE WITH OTHER POOLS AND SYSTEMS DURING PEAK HOUR:

PJM RECEIVED 1,937 MW PJM DELIVERED 200 MW

VOLTAGE REDUCTION	FROM	TO
5% all systems	8:06 A.M.	10:55 P.M.

LOAD CURTAILMENT	FROM	TO
Voluntary via radio and TV appeal	8:40 A.M.	9:23 P.M.
Non-essential utility building load	8:47 A.M.	10:55 P.M.
Pre-arranged voluntary	9:34 A.M.	9:23 P.M.

REMARKS - Continued unseasonably high temperatures and exceptionally high incidence of forced outages made the voltage reduction and load curtailments necessary to maintain a reliable power supply. Energy imports were scheduled to the limits of availability and transmission capability.

(1) MAJOR UNITS FORCED OUT

UNIT	MW	DATE OFF	DUE BACK	REASON
Keystone #1	820	7-11-70	4-1-71	Repair damage resulting from boiler explosion
Sewaren #5	344	9-2-70	11-1-70	Repair fire damage
Linden #2	110 (Redn)	9-19-70	9-27-70	Feed water heater leak
Bergen #2	300	9-21-70	9-27-70	Water wall tube leak
Brunner Isl. #3	345 (Redn)	9-22-70	N.A.	Boiler feed pump seals
Chalk Pt. #2	165 (Redn)	9-21-70	N.A.	Boiler feed pump thrust beari
Keystone #2	820	9-22-70	9-24-70	Repair brush rigging
Homer City #1	464	9-22-70	9-24-70	High pressure heater leak
Homer City #2	119 (Redn)	9-12-70	9-23-70	Returning from outage
Oyster Creek #1	530	9-22-70	9-24-70	Repair main steam by-pass val

PJM REPORT ON OPERATIONS

DATE Thursday, September 24, 1970

WEEK ENDING September 25, 1970

PEAK LOAD 23,251 MW

SHEET 4

HOUR ENDING 3:00 P.M.

INSTALLED CAPACITY 28,466 MW

INSTALLED RESERVE 5,215 MW 22.4 %

CAPACITY NOT AVAILABLE 5,929 MW

AVAILABLE RESERVE -714 MW -3.1 %

Forced outage 3,909 MW(1)

Scheduled maintenance 1,627 MW

Interim reduction 393 MW

POWER INTERCHANGE WITH OTHER POOLS AND SYSTEMS DURING PEAK HOUR:

PJM RECEIVED 2,220 MW

PJM DELIVERED 200 MW

	FROM	TO
VOLTAGE REDUCTION		
5% all systems	8:43 A.M.	9:36 P.M.
LOAD CURTAILMENT		
Voluntary via radio and TV appeal	8:00 A.M.	8:55 P.M.
Non-essential utility building load	8:03 A.M.	9:36 P.M.

REMARKS - Continued unseasonably high temperatures and high incidence of forced outages made the voltage reduction and load curtailments necessary to maintain a reliable power supply. Energy imports were scheduled to the limits of availability and transmission capability.

(1) MAJOR UNITS FORCED OUT

UNIT	MW	DATE OFF	DUE BACK	REASON
Keystone #1	820	7-11-70	4-1-71	Repair damage resulting from boiler explosion
Sewaren #5	344	9-2-70	11-1-70	Repair fire damage
Linden #2	110 (Redn)	9-19-70	9-27-70	Feedwater heater leak
Bergen #2	300	9-21-70	9-27-70	Water wall tube leak
Brunner Isl #3	345 (Redn)	9-22-70	N.A.	Boiler feed pump seals
Chalk Pt #2	165 (Redn)	9-21-70	N.A.	Boiler feed pump thrust beari
Homer City #1	464	9-22-70	9-25-70	High pressure heater leak
Keystone #2	299 (Redn)	9-22-70	9-24-70	Returning from outage

PJM REPORT ON OPERATIONS

DATE Friday, September 25, 1970
WEEK ENDING September 25, 1970
PEAK LOAD 23,560 MW
SHEET 5
HOUR ENDING 4:00 P.M.

INSTALLED CAPACITY 28,550 MW
INSTALLED RESERVE 4,990 MW 21.1 %
CAPACITY NOT AVAILABLE 5,979 MW
AVAILABLE RESERVE -989 MW -4.2 %

Forced outage 3,892 MW(1)
Scheduled maintenance 1,619 MW
Interim reduction 468 MW

POWER INTERCHANGE WITH OTHER POOLS AND SYSTEMS DURING PEAK HOUR:

PJM RECEIVED 2,185 MW
PJM DELIVERED 200 MW

VOLTAGE REDUCTION FROM TO

NONE

LOAD CURTAILMENT FROM TO

NONE

(1) MAJOR UNITS FORCED OUT

UNIT	MW	DATE OFF	DUE BACK	REASON
Keystone #1	820	7-11-70	4-1-71	Repair damage resulting from boiler explosion
Sewaren #2	344	9-2-70	11-1-70	Repair fire damage
Bergen #2	300	9-21-70	9-27-70	Water wall tube leak
Brunner Isl #3	345 (Redn)	9-22-70	N.A.	Boiler feed pump seals
Chalk Pt #2	165 (Redn)	9-21-70	N.A.	Boiler feed pump thrust beari
Homer City #1	464	9-23-70	9-28-70	High pressure heater leak
Homer City #2	329	9-24-70	9-29-70	Tube leak-reheat section

INTERCONNECTION OFFICE

PJM REPORT ON OPERATIONS

DATE Friday, June 12, 1970

WEEK ENDING June 13, 1970

PEAK LOAD 22,518 MW

SHEET 1 OF 1

HOUR ENDING 3 P.M.

INSTALLED CAPACITY 27,560 MW

INSTALLED RESERVE 5,042 MW 22.4 %

CAPACITY NOT AVAILABLE 5,033 MW

AVAILABLE RESERVE 9 MW -- %

Forced outage 2507 MW(1

Scheduled maintenance 1620 MW

Interim reduction 906 MW

POWER INTERCHANGE WITH OTHER POOLS AND SYSTEMS DURING PEAK HOUR:

PJM RECEIVED 1013 MW

PJM DELIVERED 0 MW

VOLTAGE REDUCTION FROM TO

NONE

LOAD CURTAILMENT FROM TO

NONE

(1) MAJOR UNITS FORCED OUT

UNIT	MW	DATE OFF	DUE BACK	REASON
Bergen #2	300	6-11-70	6-20-70	Tube Leak
Essex #1	114	6-11-70	6-15-70	Excess vibration
Hudson #2	135 red'n	6-3-70	6-15-70	" "
Wagner #3	318	6-9-70	6-15-70	Cracked turbine blades
Chalk Point #2	165 red'n	6-11-70	6-22-70	Primary air fan
Homer City #1 & #2	283 red'n	6-1-70	N.A.	Labor and bad coal

REMARKS: High incidence of forced outages reduced the available reserve within PJM to 9 MW. Power imports from other pools and systems provided additional reserve sufficient to preclude the use of voltage reduction to maintain a reliable power supply.

INTERCONNECTION OFFICE
TPW 6-16-70

PJM REPORT ON OPERATIONS
WEEK ENDING JULY 6, 1985

PEAK LOAD: 26,691 MW
DATE: JULY 3, 1985
HOUR ENDING: 1500

CAPACITY*

INSTALLED CAPACITY:	48,025 MW
CALCULATED INSTALLED RESERVE:	21,334 MW
INSTL RESERVE AS % OF PEAK:	79.9 %

OUTAGES*

FORCED:	6,883 MW
PLANNED/MAINTENANCE:	5,210 MW
MISCELLANEOUS ADJUSTMENTS:	-35 MW
TOTAL UNAVAILABLE CAPACITY:	12,058 MW
CALCULATED AVAILABLE RESERVE:	9,276 MW
AVAIL RESERVE AS % OF PEAK:	34.8 %

INTERCHANGE*

PJM RECEIVED:	2,997 MW
PJM DELIVERED:	0 MW

EMERGENCY PROCEDURES

VOLTAGE REDUCTION:	NONE
LOAD CURTAILMENT:	NONE

MAJOR UNIT OUTAGES*

UNIT NAME	CAPACITY	DATE OFF	DATE BACK	DATE DUE	CAUSE OF OUTAGE
T.M.I. #1	776 MW	2/18/79	-	UNKNOWN	N.R.C. RESTRICTIONS
PEACH BOTTOM #2	1051 MW	4/28/84	-	7/03/85	REFUEL & ANNUAL
MORGANTOWN #1	603 MW	2/21/85	-	7/05/85	REPAIR BLADE DAMAGE
CALVERT CLIFF #1	825 MW	4/05/85	-	9/23/85	REFUELING
HOMER CITY #2	307 MW	5/10/85	-	7/20/85	ANNUAL
EDDYSTONE #1	347 MW	6/27/85	-	7/05/85	TUBE LEAK
SALEM #2	1106 MW	6/28/85	-	7/08/85	RELIEF VALVE
MONTOUR #2	-322 MW	6/28/85	-	7/03/85	2B BLR FD PUMP
SUSQUEHANNA #2	1050 MW	6/30/85	-	UNKNOWN	GEN NEUT O.V.
EDDYSTONE #2	354 MW	7/01/85	-	7/03/85	TUBE LEAK
HUDSON #1	383 MW	7/01/85	-	7/03/85	BLR FD PUMP

* AT THE TIME OF PEAK LOAD

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Emergency Electric Regulation Docket No. 1

ORDER

BY THE COMMISSION, MARCH 30, 1970:

As used in this order, "generating unit" means a turbogenerator and the related steam, hydro or other propulsion equipment; and "normal operation" of a generating unit means its continuing availability to meet consumer demands, except during scheduled outages for repairs, tests, nuclear refueling or other procedures essential to its further use, and except during unscheduled outages caused by its physical malfunctioning or breakdown.

It appears from reports submitted to us that electric public utilities under our jurisdiction may discontinue generating units from normal operation, because of the completion of new generating units or for other reasons.

Our surveys indicate the distinct possibility that during the next several years the needs of the consuming public for electrical energy will closely approximate or exceed the available supply, particularly at times of peak loads or of unscheduled outages of large generating units; and that continuing normal operation of all generating units may be essential to prevent or minimize brownouts, blackouts or other power shortages. THEREFORE, pursuant to sections 401 and 901 of the Public Utility Law,

IT IS ORDERED:

1. Every electric public utility within our jurisdiction shall petition for andobtain our consent before discontinuing any generating unit from normal operation as defined above.

2. Every such petition shall contain such data as to recent and projected peak loads, net generating capabilities, firm power commitments and other information as will enable us to form a judgment whether such consent should be granted or refused. Public hearing may be ordered upon any such petition if the information contained therein is not sufficient for the formation of such judgment.

3. This order shall remain in full force and effect unless otherwise changed, altered, modified or rescinded by this Commission.

PENNSYLVANIA PUBLIC UTILITY COMMISSION
(signed) George I. Bloom
Chairman

ATTEST:

Assistant Secretary

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Emergency Electric Regulation Docket No. 2

ORDER

BY THE COMMISSION, APRIL 3, 1973:

The Environmental Quality Board's Air Resources Regulations (2 Pa. B. 383) provide inter alia that in certain conditions of atmospheric pollution, electric utilities shall temporarily reduce or suspend operation of generating equipment in the area affected by the pollution.

Also, unforeseen increases in consumer demand or breakdown of utility equipment may result in such demand exceeding the available supply; and, unless temporary countermeasures are taken, such excess demand could overload the system, damage equipment, and require substantial time for restoration of service.

Although an electric utility may be obliged temporarily to reduce or suspend service for either of the above causes, there is not now extant any document whereby consumers may be made aware that such reduction or suspension may occur, or of the procedure which the utility will use in the event of such occurrence.

In order to correct that situation, and also to provide the Commission with the opportunity to review, and if necessary order a revision of, each utility's intended procedures if reduction or suspension becomes necessary, the Commission prescribes the rule hereafter expressed; THEREFORE,

IT IS ORDERED:

1. That every electric public utility subject to our jurisdiction, within 30 days of service hereof, file a tariff supplement effective on one day's notice, incorporating the following rule in its electric tariff rules and regulations:

RULE____. EMERGENCY LOAD CONTROL. Pursuant to order of Pennsylvania Public Utility Commission, the following provision is incorporated in this tariff:

Whenever the demands for power on all or part of the Company's system exceed or threaten to exceed the capacity then actually and lawfully available to supply such demands, or whenever system instability or cascading outages could result from actual or expected transmission overloads or other contingencies, or whenever such conditions exist in the system of another public utility or power pool with which the Company's system is interconnected and cause a reduction in the capacity available to the Company from that source or threaten the integrity of the Company's system, a load emergency situation exists. In such case, the Company shall take such reasonable steps as the time available permits to bring the demands within the then-available capacity or otherwise control load. Such steps shall include but shall not be limited to reduction or interruption of service to one or more customers, in accordance with the Company's procedures for controlling load.

The Company shall establish procedures for controlling load including schedules of load shedding priorities to be followed in compliance with the foregoing paragraph, may revise such procedures from time to time, and shall revise them if so required by Pennsylvania Public Utility Commission. A copy of such procedures or of the revision thereof currently in effect shall be kept available for public inspection at each office at which the Company maintains a copy of its tariff for public inspection, and another such copy shall be kept on file with Pennsylvania Public Utility Commission.

2. That every such electric public utility, within 60 days after the effective date of such tariff supplement, submit to this Commission the copy of its procedures for controlling load as prescribed by the second paragraph of the foregoing rule.

PENNSYLVANIA PUBLIC UTILITY COMMISSION
(signed) George I. Bloom
Chairman

ATTEST:

Secretary

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Emergency Electric Regulation Docket No. 3

O R D E R

BY THE COMMISSION, NOVEMBER 12, 1974:

Natural disasters, labor management disputes, national defense circumstances, and international trade obstructions are some of the events that may adversely affect the availability of fuel supplies to an electric utility. Many electric utilities participate in interconnected power pools, the operations of which are significantly affected by the relative availability in each segment of the pool of one or more kinds of fuel. The availability of energy to such a utility for use by its customers can be adversely affected by an actual or threatened insufficiency of one or more kinds of fuel in any segment of the power pool.

Actual or threatened insufficiency of fuel supplies requires the taking of measures by an electric utility, individually or in concert with others, for the conservation of available fuel supplies to assure maintenance of vital services necessary for the peace, health, safety, and welfare of the public, to minimize inconvenience and assure to the extent reasonable and practicable the equal availability of energy to its customers, and to minimize adverse impact upon employment and economic activity.

Although an electric utility must under such circumstances take precautionary measures to conserve available fuel supplies, there is not now extant any document whereby its customers may be made aware that such fuel conservation measures may be instituted, or of the procedure which the utility will use in such eventuality.

In order to correct that situation, and also to provide the Commission with the opportunity to review, and if necessary order a revision of, a utilities intended procedure if it finds it necessary to institute measures to conserve available fuel supplies, the Commission prescribes the rule hereafter expressed; THEREFORE,

IT IS ORDERED:

1. That every electric public utility subject to our jurisdiction, within fifteen (15) days of service hereof, file a tariff supplement effective on one (1) day's notice, incorporating the following rule in its electric tariff rules and regulations:

RULE. Emergency Energy Conservation.

1. Pursuant to order of the Pennsylvania Public Utility Commission, the following provision is incorporated in this tariff:

Whenever events occur which are actually resulting, or in the judgment of the Company threaten to result, in a restriction of the fuel supplies available to the Company or its energy vendors, such that the amount of electric energy which the Company is able to supply is or will be adversely affected, an emergency energy conservation situation exists.

In the event of an emergency energy conservation situation, the Company shall take such reasonable measures as it believes necessary and proper to conserve available fuel supplies. Such measures may include, but shall not be limited to reduction, interruption, or suspension of service to one or more of its customers or classes of customers in accordance with the Company's procedure for emergency energy conservation.

The Company shall establish procedures for emergency energy conservation, including, if it deems necessary, schedules of service interruption and suspension priorities to be followed as prescribed by the foregoing paragraph.

The Company may revise such procedures from time to time, and shall revise them if so required by the Pennsylvania Public Utility Commission. A copy of such procedures or of the revision thereof currently in effect shall be kept available for public inspection at each office at which the Company maintains a copy of its tariff for public inspection, and another such copy shall be kept on file with the Pennsylvania Public Utility Commission.

2. That every such electric public utility, within fifteen (15) days after the effective date of such tariff supplement, submit to this Commission a copy of its procedures for emergency energy conservation as prescribed by the second and third paragraphs of the foregoing Rule.

PENNSYLVANIA PUBLIC UTILITY COMMISSION
(signed) George I. Bloom
Chairman

ATTEST:

Secretary

ORDER ADOPTED: November 12, 1974
ORDER ENTERED: NOV 19 1974

75-PRMD-9

PENNSYLVANIA
PUBLIC UTILITY COMMISSION

Public Meeting held October 1, 1975
Harrisburg, PA. 17120

COMMISSIONERS PRESENT:

Chairman Carter
Commissioner Kelly
Commissioner Bloom

75-PRMD-9 - Proposed procedure to be followed by electric, gas, water and telephone utility companies to inform this Commission of service outages.

ORDER

BY THE COMMISSION:

1. All electric, gas, water and telephone utilities holding certificates of public convenience under Sections 201 and 202 of the Public Utility Law shall adopt the following steps to notify the Commission with regard to unscheduled service interruptions.

2. All electric, gas, water and telephone utilities shall notify the Commission when 2,500 or five percent, whichever is less, of their total customers have an unscheduled service interruption in a single incident for six or more projected consecutive hours. Written notification shall be filed with this Commission within five working days after the total restoration of service. Where storm conditions cause multiple reportable interruptions as defined by this order a single composite report shall be filed. Each report shall contain the following information:

(1) The approximate number of customers involved in a single incident;

(2) The geographic area affected, in terms of the county and local political subdivision;

(3) The reason for the interruption;

(4) The projected time for service restoration;

(5) The number of company workers and others assigned specifically to the repair work;

(6) The date and time of the first information of a service interruption;

(7) The date and time that repair crews were assembled;

(7A) The date and time that the supervisor made the first call;

(8) The approximate time that repair work was started;

(9) The actual time that service was restored to the last affected customer.

3. In addition to the requirements of Paragraph 2 hereof, the company shall notify the Commission by telephone within one hour after preliminary assessment of conditions reasonably indicates that the above-mentioned criteria may be applicable. The first four items shall be used as guidelines for the telephone report. The Commission shall maintain a telephone line or lines for such purpose and shall notify each utility of the number(s) to be called.

4. The Commission shall implement a plan to govern its internal operations in receiving notification of service interruptions, in investigating such interruptions, and in assisting the customers of the utility, the utility and Government agencies in restoring service.

BY THE COMMISSION,

C J. McElwee
C. J. McElwee
Acting Secretary

(SEAL)

ORDER ADOPTED: October 1, 1975

ORDER ENTERED: October 10, 1975

[illegible]
[illegible]
[illegible]
BUREAU OF
I. S. [illegible] E.

RESERVE MARGINS

SUMMER (%)

Company	Actual 1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993
Duquesne	41.4	33.1	23.0	22.1	24.9	28.4	26.5	26.1	24.8	23.9	23.4
Met-Ed	-30.0	-16.2	8.0	6.5	6.5	3.8	2.5	1.2	28.2	25.9	27.3
Penelec	-4.2	25.0	36.3	30.4	32.7	33.2	32.3	32.2	44.0	41.9	49.0
Penn Power	33.5	47.6	56.1	53.7	51.2	59.0	56.5	54.0	51.6	49.2	46.7
PP&L	81.0	76.6	95.5	92.4	87.6	81.0	76.9	73.0	69.1	65.3	61.4
PECO	27.6	31.4	38.0	31.6	31.0	30.3	25.3	42.0	38.1	37.2	36.3
West Penn	19.6	10.9	38.1	55.5	52.2	48.7	45.4	44.8	45.2	42.7	45.2

WINTER (%)

Company	Actual 1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993
Duquesne	59.6	47.6	44.5	48.2	45.5	50.6	49.9	48.7	46.9	45.7	45.1
Met-Ed	-22.1	9.7	6.7	6.0	4.1	2.8	1.6	27.4	25.1	23.0	24.4
Penelec	0.2	16.4	16.9	13.7	13.1	12.6	12.2	22.1	19.6	18.1	23.7
Penn Power	40.7	43.3	51.7	49.2	46.8	54.5	52.0	49.7	47.2	44.8	42.4
PP&L	53.9	68.6	64.9	60.7	55.6	50.0	46.7	43.1	39.8	36.8	33.8
PECO	70.8	77.5	72.9	71.1	69.0	60.7	58.8	73.4	71.1	68.8	63.3
West Penn	23.4	31.9	41.0	37.3	33.5	29.6	26.8	26.3	26.9	29.5	27.0

RESERVE MARGINS

Reserve margins shown in the following table are calculated as the difference between planned resources and projected peak demands, expressed as a percent of projected peak demands.

Reserve margin is not of itself a sufficient index of power supply adequacy or reliability. The degree of reserves considered adequate varies among utilities due to differences in sizes and types of generating units, the number and capability of transmission interconnections, the geographic extent and configuration of the systems, and pertinent operating agreements among interconnected systems. However, since reserve margin is frequently cited, it is provided here for convenience.

COMPARISON OF STATISTICS FOR PENNSYLVANIA
1983

	Population Served	Customers Served	Peak Load (MW)	Capacity (MW)	Energy Sales (MWH)	Peak Load Growth Rates (%) 1965-1973	Peak Load Growth Rates (%) 1973-1983	Peak Load Growth Rates (%) 1984-1993
Duquesne	1,433,470	558,891	2,184	3,063	10,990,239	6.0	-0.5	2.7
Met-Ed	905,889	371,983	1,489	2,166	7,682,620	7.1	0.8	1.7
Penelec	1,528,583	522,081	2,103	2,769	10,607,898	6.1	1.6	1.8
Penn Power	350,142	126,475	567	871	3,396,488	5.5	0.6	2.4
PP&L	2,437,605	1,026,142	4,869	7,415	22,848,000	8.9	2.9	2.5
PECO	3,484,820	1,343,114	5,879	7,974	27,231,959	7.0	0.2	0.5
West Penn	1,450,000	584,739	2,556	3,613	13,461,361	5.1	2.4	2.0

	Energy Sales				Installed Generating Capability				
	% Res	% Comm	% Ind	% Other	% Coal	% Oil	% Nuclear	% Hydro	% Other
Duquesne	26.4	38.7	33.8	1.0	79.0	0.0	12.6	0.0	8.4
Met-Ed	32.8	24.0	39.0	4.2	42.9	0.0	39.8	0.9	16.5
Penelec	29.0	23.7	38.3	9.0	72.9	0.0	15.6	4.5	7.0
Penn Power	25.8	17.4	47.9	8.9	77.6	0.0	16.3	0.0	6.1
PP&L	36.0	27.1	33.8	3.1	55.9	22.1	12.7	2.0	7.3
PECO	31.1	12.1	53.2	3.7	18.7	24.0	22.8	17.5	17.1
West Penn	32.7	18.7	45.7	3.0	87.3	11.3	0.0	1.4	0.0

SOURCES FOR ECONOMIC DATA

1. Chase Econometrics, U.S. Macroeconomic Long-Term Forecast.
   Table 1.2 - data on U.S. GNP.

2. Chase Econometrics, Pennsylvania Forecast
   Table 8.2 - data on state electricity sales.
   Table 10.2 - data on PA GSP. These figures are in nominal terms.
   Table 6.2 - data on PA CPI. Used to convert PA GSP data into "real" terms.

HISTORICAL TABLES PREPARED BY CHASE ECONOMETRICS ON MAY 28, 1985

TABLE 1.2 -- GROSS NATIONAL PRODUCT
BILLIONS OF 1972 DOLLARS, SAAR

	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	74-79	79-84	74-84
GROSS NATIONAL PRODUCT	1246.3	1231.6	1298.2	1369.7	1438.5	1479.4	1475.0	1512.1	1480.0	1534.7	1639.3	3.5	2.1	2.8
CONSUMPTION EXPENDITURES	762.8	779.4	823.1	864.3	913.2	927.5	931.8	950.4	963.3	1009.2	1062.4	4.0	2.8	3.4
DURABLE GOODS	112.3	112.6	126.5	138.0	146.8	147.2	137.4	140.9	140.4	157.4	178.0	5.6	3.9	4.7
NONDURABLE GOODS	302.5	307.4	321.9	333.4	344.4	353.1	355.6	360.8	363.0	376.3	393.5	3.1	2.2	2.7
SERVICES	347.9	359.3	374.6	392.9	412.0	427.3	438.7	448.7	459.8	475.4	490.8	4.2	2.8	3.5
GROSS PRIVATE DOMES.INVEST.	195.4	154.8	184.5	214.2	236.7	236.3	208.5	230.9	194.3	221.0	289.9	3.9	4.2	4.0
FIXED INVESTMENT	183.9	161.5	176.7	200.9	220.7	229.0	212.9	219.6	204.7	224.6	265.1	4.5	3.0	3.7
NONRESIDENTIAL	135.7	119.3	125.6	140.2	158.3	169.9	165.8	175.0	166.9	171.0	204.9	4.6	3.8	4.2
STRUCTURES	43.6	38.2	39.5	40.4	44.6	49.1	48.8	53.2	53.3	49.2	56.8	2.4	3.0	2.7
PRODUCERS' DURABLE EQUIP.	92.1	81.1	86.1	99.9	113.7	120.8	117.0	121.8	113.5	121.8	148.0	5.6	4.1	4.9
RESIDENTIAL	48.2	42.2	51.1	60.6	62.4	59.1	47.1	44.5	37.8	53.6	60.2	4.2	0.4	2.2
NONFARM STRUCTURES	45.3	39.8	48.7	57.8	59.5	56.2	44.2	42.0	35.3	51.2	57.5	4.4	0.4	2.4
FARM STRUCTURES	1.1	0.8	0.9	1.0	1.0	0.8	0.8	0.5	0.6	0.4	0.4	-5.0	-12.9	-9.1
PRODUCERS' DURABLE EQUIP.	1.7	1.6	1.7	1.8	1.9	2.0	2.0	2.0	1.9	2.1	2.3	3.3	2.6	2.9
CHANGE IN INVENTORIES	11.6	-6.7	7.7	13.3	16.0	7.3	-4.3	11.3	-10.4	-3.6	24.8			
NET EXPORT GOODS & SERVICES	27.8	32.2	25.4	22.0	24.0	37.2	50.3	43.8	29.7	12.6	-15.0			
EXPORTS	108.4	103.5	110.1	112.9	126.7	146.2	159.1	160.2	147.6	139.4	146.0	6.2	-0.0	3.0
IMPORTS	80.7	71.4	84.6	90.9	102.6	109.0	108.8	116.4	117.9	126.9	161.1	6.2	8.1	7.2
GOV. PURCHASES GOODS & SERV.	260.2	265.2	265.2	269.2	274.6	278.3	284.3	287.0	292.6	291.9	302.0	1.4	1.7	1.5
FEDERAL	96.6	97.4	96.7	100.4	100.3	102.1	106.4	110.3	116.9	116.2	122.5	1.1	3.7	2.4
NATIONAL DEFENSE	66.9	66.4	64.9	65.4	65.7	67.3	70.0	73.5	79.1	84.7	89.6	0.1	5.9	3.0
NONDEFENSE	29.7	31.0	31.8	35.0	34.6	34.7	36.4	36.7	37.9	31.5	32.9	3.2	-1.1	1.0
STATE AND LOCAL	163.6	167.8	168.4	168.7	174.3	176.2	177.9	176.8	175.7	175.7	179.5	1.5	0.4	0.9

TABLE 1.2A -- GROSS NATIONAL PRODUCT
BILLIONS OF 1972 DOLLARS, SAAR
PERCENT CHANGE, ANNUAL RATE

	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984
GROSS NATIONAL PRODUCT	-0.6	-1.2	5.4	5.5	5.0	2.8	-0.3	2.5	-2.1	3.7	6.8
CONSUMPTION EXPENDITURES	-0.7	2.2	5.6	5.0	4.5	2.7	0.5	2.0	1.3	4.8	5.3
DURABLE GOODS	-7.4	0.3	12.3	9.1	6.4	0.3	-6.6	2.5	-0.3	12.1	13.1
NONDURABLE GOODS	-1.6	1.6	4.7	3.6	3.3	2.5	0.7	1.5	0.6	3.7	4.6
SERVICES	2.6	3.3	4.3	4.9	4.8	3.7	2.7	2.3	2.5	3.4	3.3
GROSS PRIVATE DOMES.INVEST.	-10.1	-20.8	19.2	16.1	10.5	-0.2	-11.8	10.7	-15.8	13.7	31.2
FIXED INVESTMENT	-8.2	-12.2	9.4	13.6	9.9	3.8	-7.1	3.1	-6.8	9.7	18.0
NONRESIDENTIAL	-1.7	-12.1	5.3	11.7	12.9	7.4	-2.4	5.5	-4.7	2.5	19.8
STRUCTURES	-7.9	-12.3	3.2	2.3	10.5	10.0	-0.7	9.1	0.3	-7.8	15.5
PRODUCERS' DURABLE EQUIP.	1.5	-11.9	6.2	16.0	13.8	6.3	-3.1	4.1	-6.8	7.2	21.5
RESIDENTIAL	-22.6	-12.5	21.3	18.6	2.8	-5.2	-20.3	-5.5	-15.0	41.7	12.2
NONFARM STRUCTURES	-24.4	-12.1	22.3	18.8	2.9	-5.5	-21.3	-5.1	-15.8	44.8	12.3
FARM STRUCTURES	69.2	-29.5	3.2	25.0	-2.5	-12.8	-8.8	-32.3	14.3	-33.3	6.3
PRODUCERS' DURABLE EQUIP.	1.5	-7.2	4.7	9.0	4.1	6.6	0.0	0.0	-6.2	10.5	9.5
EXPORTS	11.5	-4.5	6.3	2.5	12.2	15.4	8.8	0.7	-7.8	-5.6	4.7
IMPORTS	-1.3	-11.5	18.6	7.4	13.0	6.2	-0.2	7.0	1.3	7.6	27.0
GOV. PURCHASES GOODS & SERV.	2.7	1.9	-0.0	1.5	2.0	1.3	2.2	0.9	2.0	-0.3	3.5
FEDERAL	0.8	0.8	-0.7	3.8	-0.1	1.8	4.2	3.7	6.1	-0.6	5.4
NATIONAL DEFENSE	-2.1	-0.7	-2.2	0.7	0.4	2.6	3.9	5.1	7.5	7.1	5.8
NONDEFENSE	7.7	4.4	2.7	10.0	-1.1	0.3	4.7	1.0	3.1	-16.9	4.5
STATE AND LOCAL	3.9	2.6	0.4	0.2	3.3	1.1	1.0	-0.6	-0.6	-0.0	2.2

TABLE 8.2
ENERGY PRODUCTION, PRICES, AND CONSUMPTION, ANNUALLY
FORECAST PERIOD STARTS IN 1982 FOR PETROLEUM
PRODUCTS AND ANTHRACITE COAL CONSUMPTION SERIES
FORECAST PERIOD BEIGINS IN 1984 FOR OTHER COAL CONSUMPTION SERIES
FORECAST PERIOD STARTS IN 1983 FOR ALL OTHER SERIES

	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983
PA INDUSTRIAL ELECT SALES -MIL KWH	44786.0	41317.0	43366.0	44855.0	45971.0	47911.0	46109.0	46641.0	40400.0	41035.9
% CHANGE FROM YEAR AGO	-0.7	-7.7	5.0	3.4	2.5	4.2	-3.8	1.2	-13.4	1.6
PA COMMERCIAL ELECT SALES - MIL KWH	18162.0	19012.0	19805.0	20787.0	21201.0	21460.0	22038.0	22371.0	22441.9	22478.6
% CHANGE FROM YEAR AGO	-1.1	4.7	4.2	5.0	2.0	1.2	2.7	1.5	0.3	0.2
PA RESIDENTIAL ELECT SALES - MIL KWH	26673.0	27724.0	28790.0	30346.0	30961.0	31546.0	31786.0	31730.0	31651.0	32486.6
% CHANGE FROM YEAR AGO	-0.1	3.9	3.8	5.4	2.0	1.9	0.8	-0.2	-0.2	2.6
PA AVG PRICE INDUST ELECT - $/THOU KWH	21.0	25.3	25.7	28.9	30.9	33.4	41.1	46.4	54.9	51.3
% CHANGE FROM YEAR AGO	40.9	20.4	1.6	12.3	7.0	4.1	23.0	12.8	18.2	-6.5
PA AVG PRICE COMM ELECT - $/THOU KWH	32.6	37.1	38.6	42.1	44.7	47.4	53.4	60.3	60.7	58.3
% CHANGE FROM YEAR AGO	24.8	13.8	4.3	8.8	6.4	5.9	12.8	12.9	0.7	-4.0
PA AVG PRICE RESID ELECT - $/THOU KWH	35.3	40.0	41.2	44.8	46.7	49.8	56.9	63.0	72.1	(68.8) odd
% CHANGE FROM YEAR AGO	22.0	13.3	3.1	8.7	4.3	6.7	14.2	10.7	14.4	-4.5
PA INDUST NAT GAS SALES - TRIL BTU	344.0	240.0	252.8	223.9	256.6	304.5	322.4	319.6	245.4	225.4
% CHANGE FROM YEAR AGO	-1.8	-30.2	5.3	-11.4	14.6	18.7	5.9	-0.9	-23.2	-8.1
PA COMM NAT GAS SALES - TRIL BTU	107.8	114.1	116.7	104.4	107.4	106.9	110.8	121.1	120.2	120.2
% CHANGE FROM YEAR AGO	-1.5	5.8	2.3	-10.5	2.9	-0.5	3.6	9.3	-0.7	0.0
PA RESID NAT GAS SALES - TRIL BTU	296.4	291.4	310.1	302.8	305.7	295.4	291.3	293.2	281.3	279.4
% CHANGE FROM YEAR AGO	-1.1	-1.7	6.4	-2.4	1.0	-3.4	-1.4	0.7	-4.1	-0.7
PA AVG PRICE INDUST GAS - $/TRILL BTU	919.4	1410.1	1567.0	2010.8	2204.9	2514.4	3617.5	3649.2	4419.4	4703.1
% CHANGE FROM YEAR AGO	25.8	53.4	11.1	28.3	9.6	14.0	43.9	0.9	21.1	6.4
PA AVG PRICE COMM GAS - $/TRILL BTU	1313.8	1662.9	2013.7	2419.2	2640.8	2900.9	4527.1	4141.6	4952.2	5200.9
% CHANGE FROM YEAR AGO	15.8	26.6	21.1	20.1	9.2	9.8	56.1	-8.5	19.6	5.0
PA AVG PRICE RESID GAS - $/TRILL BTU	1600.8	1903.1	2194.7	2562.3	2813.9	3085.6	4396.0	4367.3	5235.6	5470.8
% CHANGE FROM YEAR AGO	13.4	18.9	15.3	16.8	9.8	9.7	42.5	-0.7	19.9	4.5

TABLE 10.2
GROSS PRODUCT ORIGINATING, ANNUAL
GROSS PRODUCT ($BILL), FORECAST PERIOD BEGINS 1984

	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983
FARM AND AGRICULTURE SERVICES	1.1	1.1	1.2	1.3	1.4	1.7	2.4	1.9	1.9	1.8
% CHANGE FROM YEAR AGO	9.2	-1.1	14.4	2.4	13.9	21.4	36.2	-19.0	-1.7	-1.6
MINING	1.6	1.9	1.9	2.1	2.0	2.4	2.7	2.8	2.9	2.8
% CHANGE FROM YEAR AGO	87.1	20.8	3.8	7.3	-5.9	24.1	9.6	5.8	1.3	-2.3
CONSTRUCTION	3.8	3.7	3.9	4.3	4.8	5.3	5.5	5.6	5.5	5.8
% CHANGE FROM YEAR AGO	5.5	-1.9	5.1	10.0	12.2	10.0	3.5	2.7	-2.5	5.8
MANUFACTURING	24.7	25.5	28.4	31.4	34.6	37.9	39.1	42.5	38.8	39.1
% CHANGE FROM YEAR AGO	8.2	3.6	11.2	10.4	10.2	9.5	3.2	8.8	-8.8	0.7
TRANSPORTATION, COMM, PUBLIC UTL	6.7	7.4	8.4	9.4	10.2	10.9	11.7	13.0	13.4	13.6
% CHANGE FROM YEAR AGO	2.9	10.3	13.6	11.2	9.4	6.3	7.0	11.2	3.5	1.5
WHOLESALE TRADE	5.5	5.8	6.0	6.4	7.1	7.8	8.4	9.3	9.1	9.5
% CHANGE FROM YEAR AGO	26.1	3.9	3.8	6.5	11.3	10.3	8.1	10.3	-2.0	4.5
RETAIL TRADE	7.0	8.0	8.6	9.3	10.2	10.8	11.3	12.2	12.9	13.9
% CHANGE FROM YEAR AGO	3.0	14.7	7.6	8.4	9.8	5.9	3.7	8.8	5.0	7.8
FINANCE, INS, REAL EST	9.3	10.2	11.3	12.6	14.2	15.9	17.8	19.2	21.3	23.9
% CHANGE FROM YEAR AGO	9.7	9.1	10.7	12.1	12.5	11.7	12.0	8.2	10.6	12.7
SERVICES	8.7	10.0	11.1	12.2	13.4	15.2	17.2	19.1	21.5	23.8
% CHANGE FROM YEAR AGO	8.9	14.5	11.5	10.0	10.1	12.8	13.4	10.8	13.1	10.3
GOVERNMENT	7.8	8.7	9.5	10.1	10.9	11.6	12.4	13.4	14.4	15.4
% CHANGE FROM YEAR AGO	6.7	11.5	9.5	6.0	8.7	5.7	7.4	8.1	7.1	7.0
TOTAL GROSS PRODUCT	76.1	82.2	90.3	98.9	108.9	119.4	128.3	139.1	141.6	149.6
% CHANGE FROM YEAR AGO	9.2	8.0	9.9	9.5	10.1	9.7	7.4	8.4	1.8	5.7

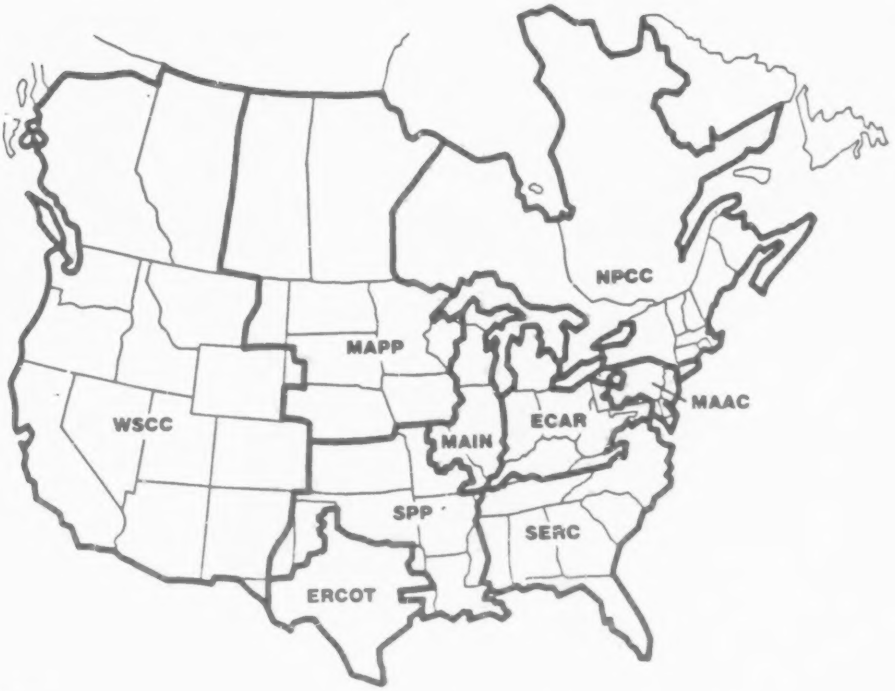
TABLE 6.2
CONSUMER PRICE INDEXES, ANNUAL
CONSUMER PRICE INDEX, 1967 = 100, FORECAST PERIOD BEGINS 1983

	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983
PA CPI FOOD AND BEVERAGES	NA	NA	180.3	191.2	210.4	231.1	250.7	269.5	283.5	289.9
% CHANGE FROM YEAR AGO	NA	NA	NA	6.0	10.0	9.8	8.5	7.5	5.2	2.3
PA CPI HOUSING	NA	NA	174.8	186.1	199.4	220.3	255.9	284.8	298.9	305.3
% CHANGE FROM YEAR AGO	NA	NA	NA	6.5	7.2	10.5	16.2	11.3	4.9	2.2
PA CPI FUEL OIL AND COAL	NA	NA	195.3	223.5	244.5	282.1	353.3	414.3	447.1	484.8
% CHANGE FROM YEAR AGO	NA	NA	NA	14.4	9.4	15.4	25.2	17.3	7.9	8.4
PA CPI APPAREL AND UPKEEP	133.8	137.5	140.9	144.3	148.1	157.7	170.6	176.7	182.7	187.1
% CHANGE FROM YEAR AGO	6.6	2.8	2.5	2.4	2.6	6.5	8.2	3.5	3.4	2.4
PA CPI TRANSPORTATION	139.2	151.1	164.2	180.3	190.8	217.6	257.9	289.4	298.2	305.4
% CHANGE FROM YEAR AGO	10.1	8.6	8.7	9.8	5.8	14.1	18.5	12.2	3.0	2.4
PA CPI MEDICAL CARE AND SERVICES	156.9	176.9	193.4	212.9	229.9	250.7	277.0	308.8	340.5	370.0
% CHANGE FROM YEAR AGO	9.0	12.7	9.4	10.1	8.0	9.0	10.5	11.5	10.3	8.7
PA CPI ENTERTAINMENT	NA	NA	159.5	166.6	172.8	186.2	197.3	216.6	227.4	235.0
% CHANGE FROM YEAR AGO	NA	NA	NA	4.4	3.8	7.7	6.0	9.7	5.0	3.3
PA CPI OTHER SERVICES	NA	NA	161.9	171.6	181.7	195.1	211.9	231.0	258.2	285.6
% CHANGE FROM YEAR AGO	NA	NA	NA	6.0	5.9	7.4	8.6	9.0	11.8	10.6
PA CPI ALL ITEMS	149.8	162.5	170.8	182.0	194.9	215.1	243.7	268.4	282.1	290.9
% CHANGE FROM YEAR AGO	11.5	8.5	5.1	6.5	7.1	10.4	13.3	10.1	5.1	3.1
US CPI, ALL ITEMS	147.8	161.3	170.5	181.6	195.4	217.5	246.8	272.3	289.1	298.3
% CHANGE FROM YEAR AGO	11.0	9.1	5.7	6.5	7.6	11.3	13.5	10.3	6.2	3.2

1985
SUMMER
ASSESSMENT

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

North American Electric Reliability Council



ECAR
East Central Area Reliability Coordination Agreement

ERCOT
Electric Reliability Council of Texas

MAAC
Mid-Atlantic Area Council

MAIN
Mid-America Interpool Network

MAPP
Mid-continent Area Power Pool

NPCC
Northeast Power Coordinating Council

SERC
Southeastern Electric Reliability Council

SPP
Southwest Power Pool

WSCC
Western Systems Coordinating Council

AFFILIATE

ASCC
Alaska Systems Coordinating Council

The North American Electric Reliability Council (NERC) was formed by the electric utility industry in 1968 to promote the RELIABILITY of bulk power supply in the electric utility systems of North America. NERC consists of nine Regional Reliability Councils and one affiliate encompassing virtually all of the power systems in the United States and Canada.

RELIABILITY, in a bulk power electric system, is the degree to which the performance of the elements of that system results in power being delivered to consumers within accepted standards and in the amount desired. The degree of reliability may be measured by the frequency, duration, and magnitude of adverse effects on consumer service.

Bulk power electric system reliability can be addressed by considering two basic and functional aspects of the bulk power system—adequacy and security.

ADEQUACY is the ability of the bulk power electric system to supply the aggregate electrical power and energy requirements of the consumers at all times, taking into account scheduled and unscheduled outages of system components.

SECURITY is the ability of the bulk power electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system components.

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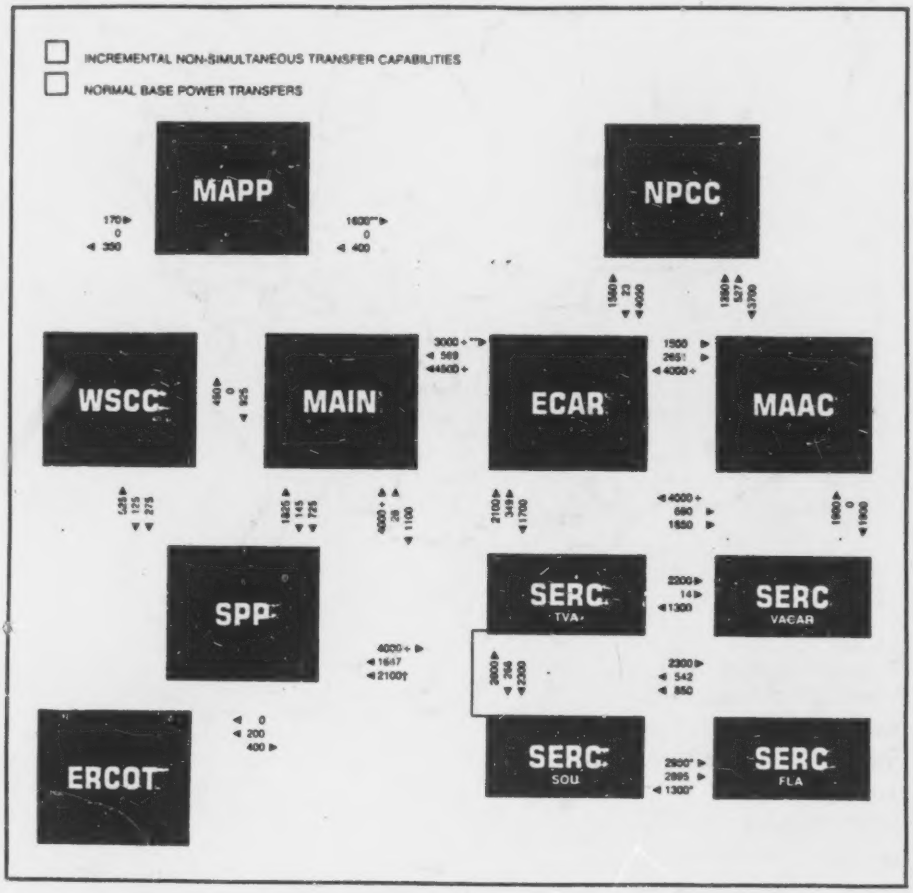
SUMMER 1985

Normal Base Power Transfers and Incremental (Non-Simultaneous) Transfer Capabilities•MW


☐ INCREMENTAL NON-SIMULTANEOUS TRANSFER CAPABILITIES
☐ NORMAL BASE POWER TRANSFERS
MAPP
NPCC
WSCC
MAIN
ECAR
MAAC
SPP
SERC TVA
SERC VACAR
SERC SOU
SERC FLA
ERCOT
170
0
300
1600
0
400
1560
23
4000
1350
527
3700
480
0
925
3000+
569
4500+
1500
2651
4000+
525
125
275
1825
145
725
4000+
28
1100
2100
349
1700
4000+
680
1850
1900
0
1900
2200
14
1300
4000+
1647
2100†
2800
264
2300
2300
542
850
0
200
400
2900*
2895
1300*

(†) With no additional import into the Southeast Subregion of SPP.

Notes to Transfer Capability Diagram

The transfer capabilities shown represent the ability of the transmission network to transfer power from one area to another for a single demand and generation pattern. It is recognized that different patterns of demand and generation will occur, resulting in variations in transfer capabilities on a day-to-day (or hour-to-hour) basis. The numbers given in this diagram should therefore be considered as representative, rather than definitive. The reader wishing more detailed information should refer to the several interregional studies for this peak demand season.

Direct current tie capabilities with ERCOT and WSCC represent equipment capabilities; otherwise, transfer capabilities were determined in accordance with NERC definitions.

The **FIRST CONTINGENCY INCREMENTAL TRANSFER CAPABILITY** is the amount of power, incremental above normal base power transfers, that can be transferred over the transmission network in a reliable manner, based on the following conditions:

1. With all transmission facilities in service, all facility loadings are within normal ratings and all voltages are within normal limits.
2. The bulk power system is capable of absorbing the dynamic power swings and remaining stable following a disturbance resulting in the loss of any single generating unit, transmission circuit or transformer.
3. After the dynamic power swings following a disturbance resulting in the loss of any single generating unit, transmission circuit or transformer, but before operater-directed system adjustments are made, all transmission facility loadings are within emergency ratings and all voltages within emergency limits.

* Those values shown with an asterisk (*) are First Contingency Total Transfer Capabilities — the total amount of power that can be transferred over the transmission network in a reliable manner, based on conditions 1, 2 and 3 in the definition above.

**With a specific operating procedure available.

(+) Indicates that no significant transmission limit found at this level.

Source

The provisions of this § 57.48 amended through January 7, 1983, effective January 8, 1983, 13 Pa.B. 131. January 7, 1983, effective January 8, 1983, 13 Pa.B. 131. Immediately preceding text appears at serial page (78459).

§57.49. Annual capacity planning report. Investigation Docket 138

Each public utility which generates all or a portion of its electric energy to serve customer demand in Pennsylvania shall submit an annual capacity planning report on or before May 1, 1983 and May 1 of each succeeding year. The information contained within the report shall conform to the following requirements:

(1) A forecast of energy demand in megawatt-hours per calendar year and number of customers (year end) displayed by component parts, as shown in Form 138-A and Form 138-A1, respectively, shall be included.

(2) A forecast of peak resources, demands and reserves in megawatts for ten-year period beginning with the current year (year zero), as indicated in Form 138-B, shall be included. The data shall be provided for both summer and winter seasons, the latter being the winter of year 0-1, 1-2, 2-3, and the like.

(3) A forecast of peak demand, resources and reserves in megawatts for the 10- to 20-year period, as indicated in Form 138C, shall be included.

(4) Reporting utilities which are subsidiaries of a larger electric utility system operated on a coordinated system basis spanning the boundaries of the Commonwealth must also file a set of Forms 138 A, B, and C for the larger system.

(5) A description of existing generating capability shall be provided in summary form as indicated in Form 138-E.

(i) The data presented in Form 138-E shall include changes in capability occurring during the past year.

(ii) A jointly owned unit shall be designated as such and the utility's share of the unit shall be indicated.

(iii) A completed copy of FERC Form 12 shall be filed annually as part of the reporting utility's submission.

(6) A description of future generating capability installations, changes, and removals shall be provided in summary form as indicated in Form 138-F.

(i) The data presented in Form 138-F shall include firm capacity transactions with other public utilities.

(ii) A jointly owned unit shall be designated as such and the utility's share of the unit shall be indicated.

(7) A description of each cogeneration and renewable resource-fueled power production facility, with which the reporting utility has a purchase agreement or contract for capacity or energy, as indicated in Form 138-G, shall be included.

(i) The data presented in Form 138-~~H~~G shall include the amount of energy in kilowatt-hours purchased from the facility during the past year and the contract capacity in kilowatts, if applicable.

(ii) Facilities with an individual annual output of less than 20,000 kilowatt-hours or capacity less than 5 kilowatts may be consolidated by customer class and energy sources — for example: residential/wind.

(8) A forecast of net generating capability distribution in megawatts and as a percentage of total capability, as indicated in Form 138-H, shall be included.

(i) Actual data for the past year and the ensuing ten years shall be provided.

(ii) The data shall be provided for both summer and winter seasons, the latter being the winter of year 0-1, 1-2, 2-3 and the like.

(9) A forecast of net generation distribution in gigawatt-hours and as a percentage of total net generation, as indicated in Form 138-I, shall be included. Actual data for the past calendar year shall be provided.

(10) A summary of demand, resource and energy data for the past year, as indicated in Form 138-J, shall be included. The peak day data shall be provided for both summer and winter seasons, the latter being the winter following the summer of the past year.

(11) For the purpose of this section, the term "current year" refers to the year in which the filing is being made.

Authority

The provisions of this § 57.49 issued under act of July 31, 1968 (P.L. 769, No. 240), § 701 *et seq*. (45 P.S. § 1701); and act of July 1, 1978 (P.L. 598, No. 116), §§ 331, 501, 504, and 1501 (66 Pa.C.S. §§ 331, 501, 504, and 1501).

Source

The provisions of this § 57.49 adopted January 7, 1983, effective January 8, 1983, 13 Pa.B. 131.

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§57.50. Forms.

The following forms have been promulgated under this chapter:

(1) Form 138-A — Historical and Forecast Energy Demand (MWH/YR); Form 138-A1 — Historical and Forecast Number of Customers (Year End).

(2) Form 138-B — Estimated Peak Resources, Demands and Reserves in Megawatts for the 10-Year Period.

(3) Form 138-C — Estimated Peak Demands, Resources and Reserves in Megawatts for the 10 — 20-Year Period.

(4) Form 138-E — Existing Generating Capability (as of January 1 — Current Year).

(5) Form 138-F — Future Generating Capability Installation, Changes and Removals for the 20-Year Period.

(6) Form 138-G — Cogeneration and Renewable Resource-Fueled Power Production Facilities.

(7) Form 138-H — Distribution of Net Generating Capability by Fuel Type for the 10-Year Period in Megawatts and as a Percentage of Total Capability.

(8) Form 138-I — Distribution of Net Generation by Fuel Type for the 10-Year Period in Gigawatt-Hours and as a Percentage of Total Net Generation.

(9) Form 138-J — Summary of Demands, Resources and Energy for the Past Year.

Company Name:

FORM 138-A. HISTORICAL AND FORECAST ENERGY DEMAND (MWH/YR)

Year	*Residential*	*Commercial*	*Industrial*	*Other*	*Total*
−5					
−4					
−3	Actual Consumption — Past Five Years				
−2					
−1	Reporting (Past) Year				
0	Actual and Estimated — Current Year				
1					
2					
3					
4					
5					
6					
7	Twenty Year Forecast				
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					

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Company Name:

FORM 138-A1. HISTORICAL AND FORECAST NUMBER OF CUSTOMERS (YEAR END)

Year	*Residential*	*Commercial*	*Industrial*	*Other*	*Total*
−5					
−4					
−3	Actual — Past Five Years				
−2					
−1	Reporting (Past) Year				
0	Actual and Estimated — Current Year				
1					
2					
3					
4					
5					
6					
7	Twenty Year Forecast				
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					

Company Name:

FORM 138-B. ESTIMATED PEAK RESOURCES, DEMANDS AND RESERVES IN MEGAWATTS FOR THE 10 YEAR PERIOD.

(Year)	0		1		2		3		4	
	Summer	*Winter*	*Summer*	*Winter*	*Summer*	*Winter*	*Summer*	*Winter*	*Summer*	*Winter*
Resources										
01 Net Capability										
02 Scheduled Imports										
03 Scheduled Exports										
04 Total Resources (01+02−03)										
05 Inoperable Capability										
06 Operable Resources (04−05)										
Peak Demand										
07 Peak Hour Demand										
08 Interruptible Demand										
09 Demand Requirements (07−08)										
Reserve Margin										
10 Margin (06−09)										
11 Scheduled Outage										
12 Adjusted Margin (10−11)										

	5		6		7		8		9	
	Summer	*Winter*	*Summer*	*Winter*	*Summer*	*Winter*	*Summer*	*Winter*	*Summer*	*Winter*
Resources										
01 Net Capability										
02 Scheduled Imports										
03 Scheduled Exports										
04 Total Resources (01+02−03)										
05 Inoperable Capability										
06 Operable Resources (04−05)										
Peak Demand										
07 Peak Hour Demand										
08 Interruptible Demand										
09 Demand Requirements (07−08)										
Reserve Margin										
10 Margin (06−09)										

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Company Name:

FORM 138-C. ESTIMATED PEAK DEMANDS, RESOURCES AND RESERVES IN MEGAWATTS FOR THE 10-20 YEAR PERIOD.

*YEAR**	*PEAK HOUR DEMAND*	*RESOURCES TO SERVE DEMAND*	*RESERVE MARGIN*
10			
11			
12			
13			
14			
15			
16			
17			
18			
19			

*Indicate:
S = Summer Peak
W = Winter Peak

Company Name:

FORM 138-E: EXISTING GENERATING CAPABILITY (AS OF JANUARY 1 — CURRENT YEAR)

Station and Unit No.	*Location*	*Date Installed*	*Unit Type*	*Fuel Type*	*Fuel Transportation Method*	*Net Capability — MW*		*Changes During Past Year*	
						Summer	*Winter*	*MW*	*Reason*

The following symbol codes shall be used when completing this form:

Unit Type

ST	Steam Turbine-non nuclear
NB	Steam-BWR Nuclear
NP	Steam-PWR Nuclear
NH	Steam-HTGR Nuclear
IC	Internal Combustion
GT	Combustion Turbine
HY	Conventional Hydro
PS	Pumped Storage Hydro
CW	Combined Cycle-Steam Portion-Waste Heat Only
CA	Combined Cycle-Steam Portion-Auxiliary Fired
CT	Combined Cycle-Combustion Turbine Portion
JE	Jet Engine
FC	Fuel Cell
SO	Solar
WM	Wind Power
GE	Geothermal
ZZ	None of the Above (Describe in footnote)
UN	Unknown at this time

Fuel Type

WH	Waste Heat
COL	Coal (general)
BIT	Bituminous Coal
SUB	Sub-Bituminous Coal
ANT	Anthracite Coal
LIG	Lignite Coal
PC	Petroleum Coke
LNG	Liquified Natural Gas
MTH	Methanol
GAS	Gas (general)
NG	Natural gas
RG	Refinery Gas
BFF	Blast Furnace Gas
COG	Coke Oven Gas
UNK	Unknown at the Time
GST	Geothermal Steam
MUL	Multi-Fueled
REF	Refuse (solid waste)
OIL	Oil (general)
FO1	No. 1 Fuel Oil
FO2	No. 2 Fuel Oil
FO4	No. 4 Fuel Oil
FO5	No. 5 Fuel Oil
FO6	No. 6 Fuel Oil
CRU	Crude Oil
TOP	Top Crude Oil
JF	Jet Fuel
KER	Kerosene
LPG	Liquid Propane Gas
RRO	Re Refined Motor Oil
SNG	Synthetic Natural Gas
UR	Uranium
PL	Plutonium
WAT	Water
TH	Thorium
SUN	Sun
WND	Wind
WD	Wood and Wood Waste
ZZ	None of the above or fuel brought to the plant site that is converted before the combustion process (see footnote)

Transportation Method

WA	Water Transportation
TK	Truck
RR	Rail
PL	Pipeline
XX	Unknown
CV	Conveyor

Status/Reason for Change

P	Planned for installation but not utility authorized
L	Regulatory approval pending but not under construction
T	Regulatory approval received but not under construction
U	Under construction, less than approximately 50% of plant completed
V	Under construction, greater than approximately 50% of plant completed
A	Generating unit capability increased (rerated or relicensed)
D	Generating unit capability decreased (rerated or relicensed)
M	Generating unit to deactivated shutdown status
S	Generating unit returned to service from deactivated shutdown status
R	Generating unit permanently removed from any service

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Company Name:

FORM 138-F: FUTURE GENERATING CAPABILITY INSTALLATIONS, CHANGES AND REMOVALS FOR THE TWENTY YEAR PERIOD.

Station and Unit No.	*Location*	*Unit Type*	*Fuel Type*	*Fuel Transportation Method*	*Net Capability - MW*		*Effective Date*	*Status*	*Estimated Construction Costs $/New Plants*
					Summer	*Winter*			

The following symbol codes shall be used when completing this form:

Unit Type

ST	Steam Turbine-non nuclear
NB	Steam-BWR Nuclear
NP	Steam-PWR Nuclear
NH	Steam-HTGR Nuclear
IC	Internal Combustion
GT	Combustion Turbine
HY	Conventional Hydro
PS	Pumped Storage Hydro
CW	Combined Cycle-Steam Portion-Waste Heat Only
CA	Combined Cycle-Steam Portion-Auxiliary Fired
CT	Combined Cycle-Combustion Turbine Portion
JE	Jet Engine
FC	Fuel Cell
SO	Solar
WM	Wind Power
GE	Geothermal
ZZ	None of the Above (Describe in footnote)
UN	Unknown at this time

Fuel Type

WH	Waste Heat
COL	Coal (general)
BIT	Bituminous Coal
SUB	Sub-Bituminous Coal
ANT	Anthracite Coal
LIG	Lignite Coal
PC	Petroleum Coke
LNG	Liquefied Natural Gas
MTH	Methanol
GAS	Gas (general)
NG	Natural Gas
RG	Refinery Gas
BFF	Blast Furnace Gas
COG	Coke Oven Gas
UNK	Unknown at the Time
GST	Geothermal Steam
MUL	Multi-Fueled
REF	Refuse (solid waste)
OIL	Oil (general)
FO1	No. 1 Fuel Oil
FO2	No. 2 Fuel Oil
FO4	No. 4 Fuel Oil
FO5	No. 5 Fuel Oil
FO6	No. 6 Fuel Oil
CRU	Crude Oil
TOP	Top Crude Oil
JF	Jet Fuel
KER	Kerosene
LPG	Liquid Propane Gas
RRO	Re-Refined Motor Oil
SNG	Synthetic Natural Gas
UR	Uranium
PL	Plutonium
WAT	Water
TH	Thorium
SUN	Sun
WND	Wind
WD	Wood and Wood Waste
ZZ	None of the above or fuel brought to the plant site that is converted before the combustion process (see footnotes)

Transportation Method

WA	Water Transportation
TK	Truck
RR	Rail
PL	Pipeline
XX	Unknown
CV	Conveyor

Status/Reason for Change

P	Planned for installation but not utility authorized
L	Regulatory approval pending but not under construction
T	Regulatory approval received but not under construction
U	Under construction, less than approximately 50% of plant completed
V	Under construction, greater than approximately 50% of plant completed
A	Generating unit capability increased (rerated or relicensed)
D	Generating unit capability decreased (rerated or relicensed)
M	Generating unit is deactivated shutdown status
S	Generating unit returned to service from deactivated shutdown status
R	Generating unit permanently removed from any service

Company Name:

FORM 138-G. COGENERATION AND RENEWABLE RESOURCE — FUELED POWER PRODUCTION FACILITIES.

Facility	*Location*	*Energy Source*	*Purchased Energy (KWH)*	*Contract Capacity (KW)*

Company Name:

FORM 138-H. DISTRIBUTION OF GENERATING CAPABILITY BY FUEL TYPE FOR THE 10 YEAR PERIOD IN MEGAWATTS AND AS A PERCENTAGE OF TOTAL CAPABILITY.

(Year)-1 (Actual)	*0*	*1*	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*
Coal - Steam										
Oil - Steam										
Nuclear										
Hydro										
Pumped Storage										
Oil Gas CT-ICE										
Total Capability										
Net Transactions										
Net Capability										

Company Name:

FORM 138-I. DISTRIBUTION OF NET GENERATION BY FUEL TYPE FOR THE 10 YEAR PERIOD IN GIGAWATT-HOURS AND AS A PERCENTAGE OF TOTAL NET GENERATION.

(Year)-1 (Actual)	*0*	*1*	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*
Coal - Steam										
Oil - Steam										
Nuclear										
Hydro										
Pumped Storage										
Oil Gas CT/ICE										
Total Net Generation										
Net Energy Import (Export)										
Total Energy For Load										

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Company Name:

FORM 138-J SUMMARY OF DEMANDS, RESOURCES AND ENERGY FOR THE PAST YEAR

PEAK DAY SUMMER ___

MW

01 Installed generating capacity
02 Firm capacity commitments from others
03 Firm capacity commitments to others
04 Reliable capacity for load (01 + 02 − 03)
05 Peak load in ___
06 Reserve available at time of peak (04 − 05)
07 Date of peak

PEAK DAY WINTER ___

MW

08 Installed generating capacity
09 Firm capacity commitments from others
10 Firm capacity commitments to others
11 Reliable capacity for load (08 + 09 − 10)
12 Peak load in ___ winter season
13 Reserve available at time of peak (11 − 12)
14 Date of peak

YEAR ___

MWH

15 Energy produced by company
16 Energy delivered to company customers
17 Energy delivered to interconnection or affiliated company
18 Energy received from interconnection or affiliated company

PHILADELPHIA ELECTRIC COMPANY
2301 MARKET STREET
P.O. BOX 8699
PHILADELPHIA, PA. 19101
(215) 841-4000

EDWARD G. BAUER, JR.
VICE PRESIDENT
AND GENERAL COUNSEL
EUGENE J. BRADLEY
ASSOCIATE GENERAL COUNSEL
DONALD BLANKEN
RUDOLPH A. CHILLEMI
E. C. KIRK HALL
T. H. MAHER CORNELL
PAUL AUERBACH
ASSISTANT GENERAL COUNSEL
EDWARD J. CULLEN, JR.
THOMAS H. MILLER, JR.
IRENE A. McKENNA
ASSISTANT COUNSEL

April 30, 1985

Mr. Conrad Six
Director, Bureau of Conservation,
Economics and Energy Planning
Pennsylvania Public Utility Commission
P. O. Box 3265
Harrisburg, Pennsylvania 17120

Re: I.D. 138 -- Investigation upon Commission Motion to Determine the Adequacy and Appropriateness of Present and Projected Generating Capacity

Dear Mr. Six:

Attached hereto for filing with the Commission are six copies of the information requested by the Commission in its Order in Investigation No. 138.

Very truly yours,

EUGENE J. BRADLEY

EJB/as
Encls.

FORM 138-A

Company Name: **Philadelphia Electric Co.**

FORM 138-A. HISTORICAL AND FORECAST ENERGY DEMAND (MWH/YR)

Year	Residential	Commercial	Industrial	Other	Total
-5	8,341,313	3,117,098	15,056,528	1,106,169	27,620,860
-4	8,014,000	3,115,000	14,916,000	1,005,000	27,050,000
-3	7,877,000	3,142,000	14,178,000	1,013,000	26,210,000
-2	8,467,240	3,283,906	14,478,093	1,002,720	27,231,959
-1	8,515,491	3,543,423	14,880,555	1,061,008	28,000,477
Current Year 0	8,668,000	3,499,000	15,065,000	1,019,000	28,251,000
1	8,626,000	3,539,000	15,061,000	964,000	28,190,000
2	8,620,000	3,610,000	14,877,000	965,000	28,072,000
3	8,620,000	3,681,000	15,122,000	966,000	28,389,000
4	8,610,000	3,741,000	15,372,000	967,000	28,690,000
5	8,598,000	3,775,000	15,629,000	969,000	28,971,000
6	8,585,000	3,853,000	15,892,000	970,000	29,300,000
7	8,580,000	3,923,000	16,160,000	972,000	29,635,000
8	8,583,000	3,990,000	16,434,000	973,000	29,980,000
9	8,597,000	4,057,000	16,716,000	974,000	30,344,000
10	8,650,000	4,127,000	16,967,000	976,000	30,720,000
11	8,725,000	4,197,000	17,224,000	977,000	31,123,000
12	8,817,000	4,269,000	17,485,000	978,000	31,549,000
13	8,917,000	4,342,000	17,751,000	980,000	31,990,000
14	9,020,000	4,416,000	18,022,000	981,000	32,439,000
15	9,149,000	4,491,000	18,297,000	982,000	32,919,000
16	9,283,000	4,567,000	18,578,000	984,000	33,412,000
17	9,417,000	4,643,000	18,865,000	987,000	33,912,000
18	9,569,000	4,720,000	19,159,000	986,000	34,434,000
19	9,724,000	4,788,000	19,453,000	987,000	34,952,000

FORM 138-A1

Company Name: PHILADELPHIA ELECTRIC COMPANY

FORM 138-A1 HISTORICAL AND FORECAST NUMBER OF CUSTOMERS (YEAR END)

Year	Residential	Commercial	Industrial	Other	Total
-5	1,190,312	116,808	5,820	736	1,313,676
-4	1,200,238	117,016	5,790	746	1,323,790
-3	1,206,944	118,407	5,616	762	1,331,729
-2	1,217,635	119,292	5,437	750	1,343,114
-1	1,230,883	121,676	5,100	750	1,358,409
0	1,238,800	122,210	5,047	761	1,366,818
1	1,248,700	122,639	5,009	771	1,377,119
2	1,257,800	123,727	4,971	781	1,387,279
3	1,266,500	124,707	4,933	791	1,396,931
4	1,273,500	125,520	4,895	801	1,404,716
5	1,280,000	125,936	4,857	811	1,411,604
6	1,286,000	127,024	4,819	821	1,418,664
7	1,291,100	127,980	4,781	831	1,424,692
8	1,295,900	128,896	4,743	841	1,430,380
9	1,298,000	129,826	4,705	851	1,433,382
10	1,300,700	130,769	4,667	861	1,436,997
11	1,302,900	131,725	4,639	871	1,440,135
12	1,304,600	132,696	4,611	881	1,442,788
13	1,305,800	133,680	4,583	891	1,444,954
14	1,307,100	134,673	4,555	901	1,447,289
15	1,308,300	135,684	4,527	911	1,449,422
16	1,309,400	136,708	4,509	921	1,451,538
17	1,310,700	137,747	4,491	931	1,453,869
18	1,311,800	138,795	4,473	941	1,456,009
19	1,313,000	139,865	4,455	951	1,458,271

Company Name: Philadelphia Electric Co.

FORM 138-B. ESTIMATED PEAK RESOURCES, DEMANDS A. RESERVES IN MEGAWATTS FOR THE 10 YEAR PERIOD

(Year)	1985 0 Summer	1985 0 Winter	1986 1 Summer	1986 1 Winter	1987 2 Summer	1987 2 Winter	1988 3 Summer	1988 3 Winter	1989 4 Summer	1989 4 Winter
Resources										
01 Net Capability	7599	8349	7858	8349	7858	8349	7858	8036	7593	8036
02 Scheduled Imports	0	0	0	0	0	0	0	0	0	0
03 Scheduled Exports	0	0	0	0	0	0	0	0	0	0
04 Total Resources (01+02-03)	7599	8349	7858	8349	7858	8349	7858	8036	7593	8036
05 Inoperable Capability	0	0	0	0	0	0	0	0	0	0
06 Operable Resources (04-05)	7599	8349	7858	8349	7858	8349	7858	8036	7593	8036
Peak Demand										
07 Peak Hour Demand	6140	4980	6160	5050	6180	5120	6200	5190	6220	5260
08 Interruptible Demand	0	0	0	0	0	0	0	0	0	0
09 Demand Requirements (07-08)	6140	4980	6160	5050	6180	5120	6200	5190	6220	5260
Reserve Margin										
10 Margin (06-09)	1459	3369	1698	3299	1678	3229	1658	2846	1373	2776
11 Scheduled Outage	0	0	0	0	0	0	0	0	0	0
12 Adjusted Margin (10-11)	1459	3369	1698	3299	1678	3229	1658	2846	1373	2776

	1990 5 Summer	1990 5 Winter	1991 6 Summer	1991 6 Winter	1992 7 Summer	1992 7 Winter	1993 8 Summer	1993 8 Winter	1994 9 Summer	1994 9 Winter
Resources										
1 Net Capability	7593	8880	8447	8880	8447	8880	8447	8702	8278	8702
2 Scheduled Imports	0	0	0	0	0	0	0	0	0	0
3 Scheduled Exports	0	0	0	0	0	0	0	0	0	0
4 Total Resources (01+02-03)	7593	8880	8447	8880	8447	8880	8447	8702	8278	8702
5 Inoperable Capability	0	0	0	0	0	0	0	0	0	0
6 Operable Resources (04-05)	7593	8880	8447	8880	8447	8880	8447	8702	8278	8702
Peak Demand										
7 Peak Hour Demand	6240	5330	6260	5410	6320	5490	6380	5570	6440	5650
8 Interruptible Demand	0	0	0	0	0	0	0	0	0	0
9 Demand Requirements (07-08)	6240	5330	6260	5410	6320	5490	6380	5570	6440	5650
Reserve Margin										
0 Margin (06-09)	1353	3550	2187	3470	2127	3390	2067	3132	1838	3052
1 Scheduled Outage	0	0	0	0	0	0	0	0	0	0
2 Adjusted Margin (10-11)	1353	3550	2187	3470	2127	3390	2067	3132	1838	3052

FORM 138-C

Company Name: **Philadelphia Electric Co.**

FORM 138-C. ESTIMATED PEAK DEMANDS, RESOURCES AND RESERVES IN MEGAWATTS FOR THE 10-20 YEAR PERIOD

YEAR	*	PEAK HOUR DEMAND	RESOURCES TO SERVE DEMAND	RESERVE MARGIN
10	1995 S	6500	8278	1778
11	1996 S	6560	8278	1718
12	1997 S	6620	8278	1658
13	1998 S	6700	8278	1578
14	1999 S	6780	8278	1498
15	2000 S	6860	8278	1418
16	2001 S	6940	8678	1738
17	2002 S	7020	8678	1658
18	2003 S	7100	8678	1578
19	2004 S	7180	8678	1498

*Indicate:

S = Summer Peak
W = Winter Peak

Company Name: Philadelphia Electric Company

FORM 138-E. EXISTING GENERATING CAPABILITY (AS OF JANUARY 1 - 1985)

Station and Unit No.		Location	Date Installed	Unit Type	Fuel Type	Fuel Transportation Method	Net Capability-MW Summer	Net Capability-MW Winter	Changes During Past Year MW	Changes During Past Year Reason
Chester	7	Chester, PA	2/7/69	GT	Oil	TK	13	18		
	8		5/20/69	GT	Oil	TK	13	18		
	9		3/6/69	GT	Oil	TK	13	18		
Conemaugh	1(J)	Indiana Co., PA	5/21/70	ST	COL	CV	176	176		
	2(J)		5/27/71	ST	COL	CV	176	176		
	D(J)		2/1/70	IC	Oil	TK	2.3	2.3		
Conowingo	1	Conowingo, MD	3/1/28	HY	WAT	-	36	36		
	2		3/1/28	HY	"	-	36	36		
	3		3/6/28	HY	"	-	36	36		
	4		4/5/28	HY	"	-	36	36		
	5		6/1/28	HY	"	-	36	36		
	6		7/1/28	HY	"	-	(1) 36	36	-102(2)	Deration
	7		6/1/28	HY	"	-	36	36		
	8		3/10/64	HY	"	-	65	65		
	9		3/25/64	HY	"	-	65	65		
	10		3/25/64	HY	"	-	65	65		
	11		5/4/64	HY	"	-	65	65		
Cromby	1	Phoenixville, PA	7/23/54	ST	COL	RR	144	147	-2	Deration
	2		9/26/55	ST	Oil	PL	201	211		
	D		6/6/67	IC	Oil	TK	2.7	2.7		
Croydon	11	Croydon, PA	5/18/74	GT	Oil	WA	39	53	-10	Deration
	12		6/18/74	GT	"	WA	39	53	-10	"
	21		6/18/74	GT	"	WA	45	59	-4	"
	22		6/18/74	GT	"	WA	34	48	-15	"
	31		8/6/74	GT	"	WA	39	53	-10	"
	32		8/8/74	GT	"	WA	45	59	-4	"
	41		7/24/74	GT	"	WA	39	53	-10	"
	42		7/24/74	GT	"	WA	45	59	-4	"

Company Name: Philadelphia Electric Company

FORM 138-E. EXISTING GENERATING CAPABILITY (AS OF JANUARY 1 - 1985)

Station and Unit No.		Location	Date Installed	Unit Type	Fuel Type	Fuel Transportation Method	Net Capability-MW		Changes During Past Year	
							Summer	Winter	MW	Reason
Delaware	7	Philadelphia, PA	8/28/53	ST	Oil	WA	126	128		
	8		4/1/53	ST	"	WA	124	128		
	9		7/24/70	GT	"	TK	15	20		
	10		5/7/69	GT	"	TK	13	18		
	11		4/19/69	GT	"	TK	13	18		
	12		5/2/69	GT	"	TK	13	18		
	D		6/6/67	IC	"	TK	2.7	2.7		
Eddystone	1	Eddystone, PA	2/5/60	ST	COL	RR	311	319	+10	Deration
	2		10/7/60	ST	COL	RR	324	333	-10	"
	3		9/24/74	ST	Oil	WA	380	380		
	4		6/29/76	ST	"	WA	380	380		
	10		5/20/67	GT	"	TK	13	18		
	20		10/11/67	GT	"	TK	13	18		
	30		3/7/70	GT	"	TK	15	20		
	40		6/21/70	GT	"	TK	15	20		
Falls	1	Falls Twp., PA	5/22/70	GT	Oil	TK	15	20		
	2		6/10/70	GT	"	TK	15	20		
	3		6/28/70	GT	"	TK	15	20		
Keystone	1(J)	Armstrong Co., PA	8/24/67	ST	COL	CV	179	179	-2(3)	Deration
	2(J)		7/23/68	ST	COL	CV	178	178	-2(3)	"
	D(J)		11/23/68	IC	Oil	TK	2.3	2.6	+.3(3)	Rerate
Moser	1	Pottstown, PA	6/9/70	GT	Oil	TK	15	20		
	2		5/29/70	GT	"	TK	15	20		
	3		6/11/70	GT	"	TK	15	20		
Muddy Run	1	Drumore Twp., PA	4/10/67	PS	WAT	-	110	110		
	2		4/10/67	PS	"	-	110	110		
	3		6/1/67	PS	"	-	110	110		
	4		6/1/67	PS	"	-	110	110		
	5		10/11/67	PS	"	-	110	110		
	6		10/11/67	PS	"	-	110	110		
	7		2/10/68	PS	"	-	110	110		
	8		2/10/68	PS	"	-	110	110		

Company Name: Philadelphia Electric Company

FORM 138-E. EXISTING GENERATING CAPABILITY (AS OF JANUARY 1 - 1985)

Station and Unit No.		Location	Date Installed	Unit Type	Fuel Type	Fuel Transportation Method	Net Capability-MW Summer	Net Capability-MW Winter	Changes During Past Year MW	Changes During Past Year Reason
Peach Bottom	2(J)	Peach Bottom, PA	7/5/74	NB	UR	TK	447	449		
	3(J)		12/23/74	NB	UR	TK	439	439		
Plymouth Mtg.	9	Plymouth Mtg., PA	6/17/71	GT	Oil	TK	29	39		
	15		6/4/71	GT	Oil	TK	29	39		
Richmond	9	Philadelphia, PA	10/6/50	ST	Oil	WA	166	175		
	21		6/7/71	GT	"	"	30	39		
	22		6/7/71	GT	"	"	30	39		
	31		5/1/71	GT	"	"	30	39		
	32		5/1/71	GT	"	"	30	39		
	41		11/4/71	GT	"	"	20	29		
	42		12/28/71	GT	"	"	20	29		
	43		9/29/71	GT	"	"	20	29		
	44		10/26/71	GT	"	"	20	29		
	51		6/26/71	GT	"	"	30	39		
	52		6/26/71	GT	"	"	30	39		
	61		7/13/71	GT	"	"	30	39		
	62		7/30/71	GT	"	"	30	39		
	71		7/8/71	GT	"	"	20	29		
	72		10/23/71	GT	"	"	20	29		
	73		12/30/70	GT	"	"	20	29		
	74		12/30/70	GT	"	"	20	29		
	81		6/7/73	GT	"	"	48	66		
	91		6/7/73	GT	"	"	48	66		
	92		6/7/73	GT	"	"	48	66		
	D		5/25/67	IC	"	"	2.7	2.7		
Salem	1(J)	Salem, NJ	6/30/77	NP	UR	TK	459	468		
	2(J)		10/13/81	NP	UR	TK	471	477		
	3(J)		6/17/71	GT	Oil	TK	16	20		
Schuylkill	1	Philadelphia, PA	7/25/58	ST	Oil	PL	166	175		
	3		3/18/16	ST	"	PL	12	54	-3(2)	Deration
	10		5/30/69	GT	"	TK	13	18		
	11		6/11/71	GT	"	TK	15	20		
	D		7/6/67	IC	"	TK	2.8	2.8		

Company Name: Philadelphia Electric Company

FORM 138-E. EXISTING GENERATING CAPABILITY (AS OF JANUARY 1 - 1985)

Station and Unit No.		Location	Date Installed	Unit Type	Fuel Type	Fuel Transportation Method	Net Capability-MW		Changes During Past Year	
							Summer	Winter	MW	Reason
Southwark	1	Philadelphia, PA	8/1/47	ST	Oil	WA	163	173	-15	Deration
	2		4/15/48	ST	"	WA	173	183	-5	"
	3		6/14/67	GT	"	TK	13	18		
	4		10/9/67	GT	"	TK	13	18		
	5		7/26/67	GT	"	TK	13	18		
	6		11/7/68	GT	"	TK	13	18		
	D		6/6/67	IC	"	TK	2.7	2.7		

Note: (J) = Jointly Owned Unit
(1) = Rating of whole plant limited to 410 MW in summer season due to required water releases.
(2) = Summer only
(3) = Winter only

Company N Philadelphia Electric Company

FORM 138-F: FUTURE GENERATING CAPABILITY INSTALLATIONS, CHANGES AND REMOVALS FOR THE TWENTY YEAR PERIOD

tion and Unit No.		Location	Unit Type	Fuel Type	Fuel Transportation Method	Net Capability - MW Summer	Winter	Effective Date	Status	Estimated Construction Costs $(New Plants)
hmond	9	Phila., PA	ST	FO6	WA	-166	-175	5-85	R	
erick	1	Limerick, PA	NB	UR	TK	+1055	+1055	4th Qtr-85	V	
thwark	D	Phila., PA	IC	FO2	TK	-2.7	-2.7	12-85	R	
thwark	1	Phila., PA	ST	FO6	WA	-163	-173	12-85	R	
thwark	2	Phila., PA	ST	FO6	WA	-173	-183	12-85	R	
mouth Mtg.	9	Ply. Mtg., PA	GT	FO2	TK	-29	-39	4-86	R	
mouth Mtg.	15	Ply. Mtg., PA	GT	FO2	TK	-29	-39	4-86	R	
chmond	21	Phila., PA	GT	FO2	WA	-30	-39	4-86	R	
chmond	22	Phila., PA	GT	FO1	WA	-30	-39	4-86	R	
chmond	31	Phila., PA	GT	FO2	WA	-30	-39	4-86	R	
chmond	32	Phila., PA	GT	FO2	WA	-30	-39	4-86	R	
chmond	41	Phila., PA	GT	FO2	WA	-20	-29	4-86	R	
chmond	42	Phila., PA	GT	FO2	WA	-20	-29	4-86	R	
chmond	43	Phila., PA	GT	FO2	WA	-20	-29	4-86	R	
chmond	44	Phila., PA	GT	FO2	WA	-20	-29	4-86	R	
chmond	51	Phila., PA	GT	FO2	WA	-30	-39	4-86	R	
chmond	52	Phila., PA	GT	FO2	WA	-30	-39	4-86	R	
chmond	61	Phila., PA	GT	FO2	WA	-30	-39	4-86	R	
chmond	62	Phila., PA	GT	FO2	WA	-30	-39	4-86	R	

Company N : Philadelphia Electric Company

FORM 138-F: FUTURE GENERATING CAPABILITY INSTALLATIONS, CHANGES AND REMOVALS FOR THE TWENTY YEAR PERIOD

tion and Unit No.		Location	Unit Type	Fuel Type	Fuel Transportation Method	Net Capability - MW Summer	Net Capability - MW Winter	Effective Date	Status	Estimated Construction Costs $(New Plants)
:hmond	71	Phila., PA	GT	FO2	WA	-20	-29	4-86	R	
:hmond	72	Phila., PA	GT	FO2	WA	-20	-29	4-86	R	
:hmond	73	Phila., PA	GT	FO2	WA	-20	-29	4-86	R	
:hmond	74	Phila., PA	GT	FO2	WA	-20	-29	4-86	R	
.aware	7	Phila., PA	ST	FO6	WA	-126	-128	12-88	R	
.aware	8	Phila., PA	ST	FO6	WA	-124	-128	12-88	R	
.aware	D	Phila., PA	IC	FO2	TK	-2.7	-2.7	12-88	R	
uylkill	3	Phila., PA	ST	FO6	PL	-12	-54	12-88	R	
erick	2	Limerick, PA	NB	UR	TK	+1055	+1055	7-90	U	
mby	2	Phoenixville, PA	ST	FO6	PL	-201	-211	12-90	R	
uylkill	1	Phila., PA	ST	FO6	PL	-166	-175	12-93	R	
uylkill	D	Phila., PA	IC	FO2	TK	-2.7	-2.7	12-93	R	
, Comb. Cycle			CC	FO6		+400	400	1-01	P	
, Comb. Cycle			CC	FO6		+400	+400	1-05	P	

ES: (J) = Jointly owned unit

Company Name: Philadelphia Electric Company

Form 138-F: Continuation

In addition to the units listed for retirement in the preceding pages, the units on the following pages will also reach the end of their nominal lives in the next 20 years. At the end of their nominal lives, these units may be retired, replaced in kind by either new facilities or purchases, or have their lives extended with new capital investment. The action to be taken will depend on economics, load growth, technology, environmental considerations and the conditions of the units. In the ID 138 forms B, C, H and I, these units or their equivalents have been assumed in existence in capacity, energy types, and energy production tables.

Comp Name: Philadelphia Electric Company

Form 138-F: Future Nominal Generation Retirements for the Twenty Year Period

Station and Unit No.		Location	Unit Type	Fuel Type	Fuel Transportation Method	Net Capability-MW		Effective Date	Status
						Summer	Winter		
Eddystone	10	Eddystone, PA	GT	FO2	TK	13	18	12-92	R
Eddystone	20	Eddystone, PA	GT	"	"	13	18	12-92	R
Southwark	3	Philadelphia, PA	GT	"	"	13	18	12-92	R
Southwark	4	Philadelphia, PA	GT	"	"	13	18	12-92	R
Southwark	5	Philadelphia, PA	GT	"	"	13	18	12-92	R
Southwark	6	Philadelphia, PA	GT	"	"	13	18	12-93	R
Schuylkill	10	Philadelphia, PA	GT	"	"	13	18	12-94	R
Delaware	10	Philadelphia, PA	GT	"	"	13	18	12-94	R
Delaware	11	Philadelphia, PA	GT	"	"	13	18	12-94	R
Delaware	12	Philadelphia, PA	GT	"	"	13	18	12-94	R
Chester	7	Chester, PA	GT	"	"	13	18	12-94	R
Chester	8	Chester, PA	GT	"	"	13	18	12-94	R
Chester	9	Chester, PA	GT	"	"	13	18	12-94	R
Delaware	9	Philadelphia, PA	GT	"	"	15	20	12-95	R
Eddystone	30	Eddystone, PA	GT	"	"	15	20	12-95	R
Eddystone	40	Eddystone, PA	GT	"	"	15	20	12-95	R
Falls	1	Falls Twp., PA	GT	"	"	15	20	12-95	R
Falls	2	Falls Twp., PA	GT	"	"	15	20	12-95	R

Comp Name: Philadelphia Electric Company

Form 138-F: Future Nominal Generation Retirements for the Twenty Year Period

Station and Unit No.		Location	Unit Type	Fuel Type	Fuel Transportation Method	Net Capability-MW Summer	Net Capability-MW Winter	Effective Date	Status
Falls	3	Falls Twp., PA	GT	FO2	TK	15	20	12-95	R
Moser	1	Pottstown, PA	GT	"	"	15	20	12-95	R
Moser	2	Pottstown, PA	GT	"	"	15	20	12-95	R
Moser	3	Pottstown, PA	GT	"	"	15	20	12-95	R
Schuylkill	11	Philadelphia, PA	GT	"	"	15	20	12-96	R
Richmond	81	Philadelphia, PA	GT	"	"	48	66	12-98	R
Richmond	91	Philadelphia, PA	GT	"	"	48	66	12-98	R
Richmond	92	Philadelphia, PA	GT	"	"	48	66	12-98	R
Croydon	11	Croydon, PA	GT	"	WA	39	53	12-99	R
Croydon	12	Croydon, PA	GT	"	"	39	53	12-99	R
Croydon	21	Croydon, PA	GT	"	"	45	59	12-99	R
Croydon	22	Croydon, PA	GT	"	"	34	48	12-99	R
Croydon	31	Croydon, PA	GT	"	"	39	53	12-99	R
Croydon	32	Croydon, PA	GT	"	"	45	59	12-99	R
Croydon	41	Croydon, PA	GT	"	"	39	53	12-99	R
Croydon	42	Croydon, PA	GT	"	"	45	59	12-99	R
Keystone	1(J)	Armstrong Co.	ST	FO6	CV	-179	-179	12-02	R

System Planning Division

Company Name: Philadelphia Electric Co.

FORM 138-G

FORM 138-G COGENERATION AND RENEWABLE RESOURCE - FUELED POWER PRODUCTION FACILITIES

Facility	Location	Energy Source	Purchased Energy (KWH)	Contract Capacity (
Morris (15 kW) Installed 12/80	Parkesburg	Wind	112	-
Soliwoda (4 kW) Installed 4/81	West Grove	Wind	-0-	-
Moss (15 kW) Installed 11/81	Gap	Wind	-0-	-
Bowman (10 kW) Installed 7/82	Schwenksville	Hydro	-	-
Dinnerman (5 kW) Under Construction	Gladwyne	Hydro	-	-
Moyer Installed 5/83	Plumsteadville	Wind	-0-	-

Company Name: Philadelphia Electric Co.

FORM 138-H. DISTRIBUTION OF NET GENERATING CAPABILITY BY FUEL TYPE FOR THE 10 YEAR PERIOD IN MEGAWATTS AND AS A PERCENTAGE OF TOTAL CAPABILITY

	(Year) -1 (Actual) 1984	0 1985	1 1986	2 1987	3 1988	4 1989	5 1990	6 1991	7 1992	8 1993	9 1994
Coal - Steam	1488 (20.3)	1488 (19.6)	1488 (18.9)	No change from previous year.	No change from previous year.	1488 (19.6)	No change from previous year.	1488 (17.6)	No change from previous year.	No change from previous year.	1488 (18.0)
Oil - Steam	1891 (25.8)	1725 (22.7)	1389 (17.7)			1127 (14.8)		926 (11.0)			760 (9.2)
Nuclear	1816 (24.8)	1816 (23.9)	2871 (36.5)			2871 (37.8)		3926 (46.5)			3926 (47.4)
Hydro	410 (5.6)	410 (5.4)	410 (5.2)			410 (5.4)		410 (4.8)			410 (5.0)
Pumped Storage	880 (12.0)	880 (11.6)	880 (11.2)			880 (11.6)		880 (10.4)			880 (10.6)
Oil/Gas CT/ICE	1280 (17.4)	1280 (16.8)	820 (10.5)			817 (10.8)		817 (9.7)			814 (9.8)
Transactions	-435 (-5.9)	0	0			0		0			0
Total Capability	7330 (100.0)	7599 (100.0)	7858 (100.0)			7593 (100.0)		8447 (100.0)			8278 (100.0)

Company Name: Philadelphia Electric Co.

FORM 138-I. DISTRIBUTION OF NET GENERATION BY FUEL TYPE FOR THE 10 YEAR PERIOD IN GIGAWATT -HOURS AND AS A PERCENTAGE OF TOTAL NET GENERATION

	(Year) -1 (Actual) 1984	0 1985	1 1986	2 1987	3 1988	4 1989	5 1990	6 1991	7 1992	8 1993	9 1994
Coal-Steam	7324 (24.3)	6517 (21.4)	7322 (24.1)	6882 (22.8)	7001 (23.0)	6796 (22.1)	6669 (21.4)	6921 (22.0)	6902 (21.7)	6973 (21.6)	7119 (21.8)
Oil-Steam	3761 (12.5)	2695 (8.9)	2482 (8.2)	1646 (5.5)	1788 (5.9)	1879 (6.1)	1667 (5.4)	1554 (4.9)	1764 (5.5)	1837 (5.7)	1795 (5.5)
Nuclear	6462 (21.4)	12055 (39.7)	15417 (50.8)	16019 (53.1)	17120 (56.3)	17132 (55.6)	20634 (66.3)	21306 (67.6)	22953 (72.0)	21906 (68.0)	22223 (68.1)
Hydro	2085 (6.9)	1730 (5.7)	1785 (5.9)	1730 (5.7)	1733 (5.7)	1728 (5.6)	1735 (5.6)	1728 (5.5)	1736 (5.5)	1730 (5.4)	1727 (5.3)
Pumped Storage	-479 (-1.6)	-501 (-1.6)	-498 (-1,6)	-596 (-2.0)	-612 (-2.0)	-581 (-1.9)	-573 (-1.8)	-561 (-1.8)	-563 (-1.8)	563 (-1.7)	-552 (-1.7)
Oil/Gas CT/ICE	425 (1.4)	136 (0.4)	126 (0.4)	85 (0.3)	166 (0.5)	182 (0.6)	165 (0.5)	257 (0.8)	353 (1.1)	338 (1.0)	476 (1.5)
Total Net Generation	19578 (64.9)	22632 (74.5)	26634 (87.8)	25766 (85.5)	27196 (89.4)	27136 (88.1)	30297 (97.3)	31205 (99.0)	33145 (104.0)	32221 (100.0)	32788 (100.5)
Net Energy Import (Export)	10580 (35.1)	7753 (25.5)	3690 (12.2)	4385 (14.5)	3218 (10.6)	3652 (11.9)	848 (2.7)	308 (1.0)	-1274 (-4.0)	12 (0.0)	-166 (-0.5)
Total Energy for Load	30158 (100.0)	30385 (100.0)	30323 (100.0)	30151 (100.0)	30414 (100.0)	30787 (100.0)	31145 (100.0)	31513 (100.0)	31871 (100.0)	32233 (100.0)	32622 (100.0)

(1) For the year 1984 the sale of Salem #2 energy to Jersey Central Power & Light has been considered in this table as an export. This sale terminates in 1984.

FORM 138-J

Company Name: Philadelphia Electric Co.

Form 138-J. SUMMARY OF DEMANDS, RESOURCES AND ENERGY FOR THE PAST YEAR

PEAK DAY SUMMER 1984

		MW
01	Installed generating capacity	7753
02	Firm capacity commitments from others	0
03	Firm capacity commitments to others	35
04	Reliable capacity for load (01 + 02 - 03)	7718
05	Peak load in 1984	5925
06	Reserve available at time of peak (04 - 05)	1793
07	Date of peak	June 13, 1984

PEAK DAY WINTER 84-85

		MW
08	Installed generating capacity	7765
09	Firm capacity commitments from others	0
10	Firm capacity commitments to others	0
11	Reliable capacity for load (8 + 9 - 10)	7765
12	Peak load in 84-85 winter season	5238
13	Reserve available at time of peak (11 - 12)	2527
14	Date of peak	January 21, 1985

YEAR 84

		MWH
15	Energy produced by company	19,578,000
16	Energy delivered to company customers	29,395,000 (1)
17	Energy delivered to interconnection or affiliated company	196,000
18	Energy received from interconnection or affiliated company	12,171,000

(1) Includes the Salem #2 energy (1395 GWh) to Jersey Central Power & Light.

Table

Individual Program Expenditures and Results by Utilities

Electric Utilities

Company	Program	Expenses	Savings	
			Peak (KW)	Energy (MWH)
Duquesne Light	Energy Conservation Educational & Informational Personal Contact Program	$ 458,538	10,845	6,670
	Residential Energy Conservation Ed. & Inf. Personal Contact Program	165,469	55	210
	Energy Conservation Ed. & Inf. Support Program	648,159	included above	
	Residential Conservation Service	123,778	-	45
Metropolitan Edison Company	Program to Achieve Cost of Energy Reduction (PACER)	21,684	-	-
	Residential Energy Conservation Action Program (RECAP)	572,542	3,366	1,948.7
	Time-of-Day	644,806	16,439	10,959
	Residential Cnservation Service	11,970	-	-
	Fluorescent Lamp Rebate	164,261	1,320	3,961
Pennsylvania Electric Company	Res. Consumer Education & Info. Program	441,707	-	-
	Res. Energy Man. Program	2,650,363	9,813	11,618
	Employee Thermal Storage Space Heating Program	5,645	52	-
	Comm. & Ind. Consumer Contact Program	876,400	65,000	162,500

Company	Program	Expenses	Savings	
			Peak (KW)	Energy (MWH)
Penelec (Continued)	Energy Eff. Fluorescent Lighting Program	153,000	800	2,400
	Cogeneration Development Program	39,400	-	-
	Remote Control of Res. Water Heaters	60,874	-	-
	Conservation Home	2,517	4	10
	Wind Energy Evaluation Prog.	12,375	-	-
	Solar Water Heating Seminar	800	1.5	2
	Solar Domestic Water Heater/Monitoring Program	3,600	-	-
Pennsylvania Power Company	Education & Informational Personal Contact Program	486,674	1,009	175
	Education & Informational Group Program	367,139	-	-
	Residential Conservation Service Program	17,078		
	Optional Control Service Rider Rate	2,323	339	-
Pennsylvania Power & Light Company	Residential New Construction Program	849,412	597	-
	Residential Space & Water Heating Conversion Program	766,020	102	-
	Agricultural Marketing Program	46,087	-	-
	Insulation Levels for New Residence BECS/Act 222	61,819	23,486	76,348
	Residential Employee Assistance Program	3,506	108	633

Company	Program	Expenses	Savings	
			Peak (KW)	Energy (MWH)
	Commercial and Industrial			
PP&L (Continued)	Efficient Use of Electric Energy Customer Applications	X 803,88~~3~~2	-	-
	Economic Development Initiatives	-	49,000	-
	Association of Energy Managers	32,260		
	Architect & Engineer Program	26,727		
	PP&L Wattline	17,963		
	Energy Workshops	64,592		
	Industrial & Commercial Conference & Exposition	73,312	-	-
	School Energy Education Program	111,768	-	-
	Mobile Energy Exhibit	85,759	-	-
	Teacher Training	26,003	-	-
	Special Projects	10,278	-	-
	Energy Information Speakers Program	64,231	-	-
	Insulation Machine Program	782	-	-
	Seal It/Wrap It Program	14,329	-	-
	Off-Peak Hydronic Ceramic Thermal Storage System Investigation	55,573	-	-
	Passive Solar Spacing Heating in Regionally Styled Housing	X 52~~9~~6	-	-
	Residential Load Controller	4,361	-	-

Company	Program	Expenses	Savings	
			Peak (KW)	Energy (MWH)
PP&L (Continued)	Least Impact Systems Metering Program	94,620	-	-
	Residential Heat Pump Water Heater Test	6,779	-	-
	Dual-Fuel Heat Pump Study	12,126	-	-
	Residential Off-Peak Water Heating Study	7,709	-	-
	Low-Cost Thermal Storage Tanks	43,707	-	-
Philadelphia Electric Company	Excellence in Energy Efficiency	26,500	534	4,271 (MWH) 9,240 (MCF)
	Low Income Electricity Conservation Education	3,825		23 (MWH)
	Philadelphia Energy Coordinating Agency	6,600	-	-
	Fuel Cell Test Program	44,100	-	-
	Summer Cooling	5,300	310	940 (MWH)
	City of Philadelphia Municipal Energy Conservation Program	2,650	-	14,130 (MWH)
	Interdenominational Clergy Energy Council	25,000	-	-
	School District of Philadelphia Energy Conservation Program	5,300		4,300 (MWH) 172,100 (MCF)
	Seminar for Large Commercial and Industrial customers	51,800		2,420 (MWH) 565 (MCF)
	Energy Conservation Information Program	32,500	-	-
	Audio-Visual Communications Studio	6,300	-	-
	Technical Analysis Bulletin	1,060	-	-
	Energy Education Advisory Council	331,000	-	-

Company	Program	Expenses	Savings Peak (KW)	 Energy (MWH)
PeCo (Continued)	Heat Pump Program	393,500		8,725 (MWH) 19,578 (MCF)
	Customer Bill Inserts and Literature on Conservation	65,000	-	-
	Consumer Affairs at Philadelphia Electric Company	75,000	-	-
	Conservation Advertising	700,000	-	-
	Warm Room Program	1,060		1,726 (MWH) 25,828 (MCF)
	PeCo Energy Conservation News	730	-	-
	Apartment Owners/Manager Energy Management Seminar	6,650	-	-
	Architect/Engineer Energy Management Conference	20,300	-	-
	School Administration Energy Management Seminar	6,975	-	-
	Citizens Coalition for Energy Efficiency	13,800	-	-
	Vocational-Technical School Conservation Training	1,325	-	-
	Energy Conservation Displays and Exhibits	134,500	-	-
	PeCo/PGW Save-It-Now Home Weatherization Workshops	13,975		10 (MWH) 6,318 (MCF)
	Industrial & Commercial Services	988,100		36,560 (MWH) 596,775 (MCF)

Company	Program	Expenses	Savings Peak (KW)	 Energy (MWH)
PeCo. (Continued)	Energy Conservation & Customer Operations	2,897,340	-	-
	Suburban Street Lighting Program	30,000	-	61 (MWH)
	Conservation Impact Measurement and Evaluation	286,000	-	-
	Residential Gas Outdoor Light Information Program	27,000	-	280 (MCF)
	Load Management Options for Comm./Ind. customers	2,650	-	-
	Single Point Meter Conversion Program	13,250	-	-
	Heat Pump Water Heater	2,650	20	140 (MWH)
	Conservation in Religious Buildings	18,200	-	-
	High Efficiency Lighting Program	25,600	207	621 (MWH)
	TEAM (The Energy Awareness Managers)	13,950	-	-
	Energy Management Action Course	2,750	1,000	8,500 (MWH)
	Ground Water Heat Pump Test Program	1,990	-	-
	Energy Savings Appliance Stores	590,480	420	2,005 (MWH) 6,375 (MCF)
	Tighten-Up Low-Cost Conservation Program	124,800	2	49 (MWH) 1,320 (MCF)
	Residential Conservation Service Program	380,690	153	353 (MWH) 4,710 (MCF)
	Delaware Co. Intermediate Unit Energy Awareness Conservation Demonstration Project	3,180	100	370 (MWH) 1,965 (MCF)

Company	Program	Expenses	Savings	
			Peak (KW)	Energy (MWH)
PeCo (Continued)	Weatherization Program in Conjunction with Edison Electric Institute	5,600	-	125 (MCF)
	Low-Income Energy Conservation Demonstration Program	37,400	70	-
	Compressed Natural Gas Vehicle Program	214,800	-	-
	Solar Photovoltaic Systems	34,450	-	-
	Solar Ice Maker Storage System	25,150	-	-
	Solar Domestic Water Heating Consumer Info & Asst. Program	5,300	-	-
	Solar Involvement & Assistance	11,600	-	-
	Electric Vehicle Demonstration Program	104,000	-	-
	Rate OP Off-Peak Service	139,125	490	
	Residential Experimental Time-of-Use Rate	55,650	-	-
	Rate GS Night Service Rider	39,500	590	91 (MWH)
	Rate PD Night Service Rider	26,500	720	3,000 (MWH)
	Rate HT Time-of-Use Adjustment	6,625	-	182,000 (MWH)
	Curtailment HT Rider	795	5,500	680
	Interruptible Natural Gas Rates	26,500	-	-
	Load Profile Patterns for Industrial & Commercial Accounts	53,000	-	-
	Innovative Rates & Metering Committee	79,500	-	-

Company	Program	Expenses	Savings Peak (KW)	 Energy (MWH)
UGI Corporation	Residential Assistance	18,900	-	-
West Penn Power Company	Water Heater Insulation Program	69,630	-	1,359
	Heat Pump Water Heater Program	1,020	-	-
	Space Heating Capacity Limitation Program	69,630	-	-
	Add-On Heat Pump Program	1,460	-	-
	Energy Efficient Appliances	92,650	-	-
	Energy Efficient Home	97,960	-	955
	Residential Conservation Service Program	58,674	-	94
	Targeted Lifeline Conservation Program	1,481,610		4,384
	Space Heating Conservation	75,210		8,620
	Air Conditioning Conservation	29,830		3,430
	Indoor Lighting Conservation	61,110		6,053
	Outdoor Lighting Conservation	12,990		1,300
	Commercial Cooking Energy Conservation	2,380		278
	Commercial Refrigeration Energy Conservation	5,370		524
	Commercial Dishwashing	23,960	-	2,390
	Energy Management Systems	18,833	-	1,809
	Water Heating Energy Conservation	8,750	-	863
	Add-On (Duel Fuel) Heat Pumps	1,100	-	21

Company	Program	Expenses	Savings Peak (KW)	 Energy (MWH)
West Penn (Continued)	Heat Pump Water Heater	770	-	-
	Process Heating Efficiency	4,710	-	1,268
	Process Insulation	6,900	-	1,854
	Heat Recovery	2,770	-	745
	Lighting Conservation	26,640	-	7,146
	Demand Control	108,420	-	29,115
	Motor Selection	37,890		10,164
	Space Conditioning	9,850		2,646
Gas Utilities Company				
Carnegie Natural Gas Company	Outdoor Gas Light Program Residential Conservation Service Program	110 1,226	- -	- -
Columbia Gas of Pennsylvania, Inc.	Consumer Information Program Residential Conservation Service Program	N/A 52,320	- -	- -
Equitable Gas	Informal Audits	15,600	-	15,000
	Technical Assistance to Industrial Customers	9,100	-	15,090
	Flue Gas Analysis	1,950	-	5,000
	Conservation Information Industrial & Commercial	155	-	
	Industrial Energy Utilization Seminars	1,275	-	13,000
	Speakers Bureau	9,000	-	10,000
	Customer Information Program	12,780	-	50,000

Company	Program	Expenses	Savings Peak (KW)	Savings Energy (MWH)
Equitable (Continued)	Care/Use Demonstrations	3,925	-	-
	Senior High Energy Efficiency	3,100	-	-
	Appliance Home Calls	14,000	-	-
	High Efficiency Heating Equipment Display	5,450	-	40,000
	Direct Mailings	9,700		53,000
	Appliance and Heating Dealer Promotion	46,500		53,000
	New Construction Promption	29,100		53,000
	Residential Conservation Service Program	155,900	-	-
National Fuel Gas Distribution Corporation, Inc.	Speakers' Bureau	-	-	-
	Energy Education & Senior Citizen Programs	94,752	-	-
	Energy Surveys	112,264	-	-
	Conservation Displays	-	-	-
	School Range Program	39,290	-	-
	Better Living Expo - 1984	3,950	-	-
	Consumer Energy Management Program	217,972	-	-
	Conservation Related Advertising	227,491	-	-
	Low Income Residential Conservation Assistance Program	X X94,136	-	-
	Residential Conservation Service Program	75,507	-	-
North Penn Gas Company	Consumer Education Program	1,080	-	-
	Residential Conservation Service Program	9,495	-	-

Company	Program	Expenses	Savings Peak (KW)	 Energy (MWH)
Pennsylvania Gas and Water Company	Home Shows	8,152	-	-
	Educational Services	3,368	-	-
	Civic Organizations	-	-	-
	Energy Management Assistance	1,030	-	-
	Hand Out Materials	500	-	-
	KEEN	1,700	-	-
	Local Energy Councils	-	-	-
	Residential Conservation Service Program	51,974	-	-
	Showroom Conservation Displays	-	-	-
	ASHRAE	-	-	-
	Equipment Requirements	-	-	-
	Thermal Protection	-	-	-
	Conservation Advertising	12,357	-	-
Peoples Natural Gas Company	Employee Purchase Program	28,507	-	-
	Promotion of Gas Equipment	224,490	-	-
	New Residential Construction	58,062	-	-
	Commercial Food Service	92,714	-	-
	Commercial Water Heater Program	62,374	-	-
	School Administrators Informational Meetings	4,754	-	-

Company	Program	Expenses	Savings Peak (KW)	 Energy (MWH)
Peoples (Continued)	Key Account Meetings	4,260	-	-
	Contract Customer Meetings	4,116	-	-
	High Efficiency Heating Equipment Program	91,462	-	-
	Flue Gas Analysis	23,648	-	-
	Gas-fired Equipment New Technology	39,194	-	-
	AV Program	2,861	-	-
	Film Library	3,532	-	-
	Energy Efficient Literature	5,800	-	-

The CHAIRMAN. Thank you.

Mr. Downey.

STATEMENT OF JOHN T. DOWNEY, CHAIRMAN, CONNECTICUT PUBLIC UTILITIES CONTROL

Mr. DOWNEY. Senator, good afternoon.

I want to start with a disclaimer. I too have cut and slashed, I hope to the bone, but the disclaimer is that, while I refer to a number of regional New England issues, I'm here speaking as the chairperson of the Connecticut Commission and I'm not authorized to speak for the New England States or the region as a whole.

I might mention that Connecticut has a generation mix now of 57 percent fossil fuel, 41 percent nuclear fuel, and 2 percent hydro. The nuclear industry has served us very well over the years. I might note that diversification of our energy mix is State policy, fixed in statute.

We never forget, however, that Connecticut is part of New England and that our energy fates are intertwined with our neighbors that comprise the region. And indeed, many of us see our good neighbors to the North in Quebec and the Maritimes as sharing regional energy concerns, and, of course, we have made a cost-benefit analysis and estimated the pros and cons of seeking energy from Canada. And I must say that at this time, in our circumstances, the benefits greatly in our judgment outweigh the risks, which are certainly true risks.

We are, as you know, members of New England Power Pool. That has great ramifications. We have a single grid. We have an economic dispatch centrally organized that enables us to have a great deal more reliability per company than might otherwise be the case and sees to it that the power is dispatched on a moment-to-moment basis in the most economic fashion.

Question 1, I wanted to address that the staff proposed was, will serious shortages of baseload generating capacity occur in individual utility systems by the early 1990's? And as I answer, assuming timely completion of Seabrook One and Milstone 3, both scheduled to come on line next year, New England is unlikely to experience serious shortages of baseload generating capacity through the early 1990's. However, given present trends in demand and construction, I think it is prudent to anticipate that we will need major additions by the mid-to late-1990's, and I might mention that that is just around the corner, the day after tomorrow in terms of leadtimes. So this hearing and this procedure is certainly timely from our perspective.

Now, should either of these two nuclear plants fail to be completed in a timely fashion, then we may well experience serious shortages of baseload generating capacity by the early 1990's. But given completion of those two plants, factoring in power purchases under phase 1 and phase 2 of the Hydro of Quebec agreements, factoring in conservation, significant amounts of cogeneration, small power production, retrofitting existing plants, Connecticut and New England will, as I say, likely nonetheless need new baseload generation by the mid-to late-1990's.

I might mention as an aside, Senator, that if activity on our commission is a gauge, cogeneration and refuse energy are two ideas whose time has certainly come in Connecticut, and we're being literally besieged by people who want to develop those sources of energy.

Moving along to question 4, a very interesting one: Do electric utilities have an incentive to minimize their investment in new central station generating plants? I start by pointing out that electric utilities share a public service obligation to ensure capacity sufficient to meet their customers' needs, and, of course, traditionally there has been an incentive to build new central station generating plants.

Companies, seeing that as a management prerogative, proceeded to construct plants with a certain confidence that costs prudently incurred would be included in the rate base once the plant became used and useful. The harsh experience of the past decade and more and the myriad forces being brought to bear on companies' decisions seem to be impelling companies seeking to meet their obligations toward smaller and consequently more dispersed, less capital intensive base load units, with shorter construction leadtimes. The effort is, of course, to reduce the consequences of miscalculation of load projections.

Prudent management is also searching for means to defer the need for this additional base load capacity, utilizing all those other sources that I listed earlier and the whole rubric of what we call in Connecticut integrated supply-demand planning. However, in this commissioner's view—and I feel strongly about this—solutions which envision a future of decreased system reliability, scheduled brownouts, rolling blackouts or power interruptions are not acceptable, nor do I believe that the public would welcome such a future.

One thing I am very certain about, and it's a gut feeling and it comes from a lifetime of experience rather than a demonstrated statistical analysis: The social and economic costs of too little capacity far exceed the cost to the public of too much capacity.

One characteristic I think has been made clear this morning and this afternoon as well in current management thinking on base load additions is an emerging determination of management not to move forward on construction of major base load units absent clear, unequivocal support from regulators, legislators, Government, and the public for both the construction, the size of the plant, the choice of fuel.

All this is quite understandable, but there is a danger here which I'm alert to of an abdication of responsibility, a shrugging of the shoulders, if you will, of feeling that, we've tried everything and we've had the hell kicked out of us, so let society deal with this when the time comes. Consequently, leadtimes dwindle, so that options too dwindle and disappear, and solutions are not necessarily the best solutions.

Also, as to the question of the so-called rate suppression decisions, isn't it odd how that beating your spouse simile came to my mind as well. But I will only say that one person's rate suppression may be someone else's protection of the consumers.

I believe in strict scrutiny of a company's plans and expenditures, and when we find imprudency we adjust the company's rates accordingly. Companies, I'm sure we all agree, must be held accountable for their decisions as they impact ratepayers. And I might point out that prudence investigations and prudency analyses are certainly nothing new in the regulatory scheme of things.

However, prudency traditionally has been analyzed using some variety of the reasonable person standard. And as far as I'm concerned, I would oppose any shift in the definition of prudency that would permit post hoc judgments when penalize companies for events subject over which they could have had no knowledge, nor exercise control.

Having said this, I think we have to recognize that the world is changing, regulation is changing, and companies are well advised to develop flexibility to meet those changes. There's no use simply grumbling about regulatory barriers. Concepts such as rate phase-in of major capacity additions, which a decade ago might have been deemed shocking, are now gaining regulatory and public acceptance, to the point where our companies in Connecticut are proposing phase-ins for the nuclear plants that are coming on line shortly.

In Connecticut we're also looking at a shift in the definition of "used and useful" from simply meaning commercial operation to adding a quality of providing net benefits to the customers. Around the country, as we know, there are all sorts of new ideas in the air, possibilities of introducing competition into some aspects of the business, opening electric generation to nonutility owners, and perhaps disaggregating the elements of the business—generation, transmission, and distribution—and applying varying degrees of regulation and competition to those components.

I think it ought to be understood that, while none of us, I trust, would advocate changing the rules in the middle or even in the late stages of any game, we must recognize that some of these games—and I'm speaking, I suppose, of projects—were begun so long ago, so many conditions have changed over time, and rigid adherence to traditional principles could have such consequences so inimical to the ratepayers, that some shifts are I think imperative as well as inevitable.

And we all must adjust to necessary change, bearing in mind that a company operating over time on the brink of financial collapse is unlikely to provide customers either with adequate service or reasonable rates.

In conclusion, I'd simply like to stress a couple of deeply felt but rather simple concepts, and reiterate that in order for New England to avoid serious shortages of base load generating capacity in the early 1990's, both Seabrook 1 and Milstone 3 must be completed in a timely fashion, safely, and at a bearable cost.

The Connecticut Commission has been firm to date in its support of Seabrook 1. And as I have often said, I discern that the quality of management is there, the quality of construction has not seriously been challenged. Most surprising to me, given the vicissitudes of that plant, the money is there. There are people who want to invest in this project.

Finally, the driving imperative for us, I think, in Connecticut is that the need for that power is there. So I would say let's get on with completing that project.

Second, while every effort to obtain new sources of energy should be pursued vigorously, as I said, any solution that is based on decreased system reliability, power interruptions, scheduled brownouts and blackouts, and what I would consider a dramatic change in our way of life and material standard of living is unacceptable.

Third, while excess generating capacity is a valid concern and at certain times and places may impose serious and even unacceptable burdens on ratepayers, the social and economic consequences of undercapacity are far more costly.

Fourth, utility bankruptcy is not an acceptable means to resolve utility problems, nor of ensuring adequate service at reasonable rates.

A small point as to excess capacity, Mr. Chairman. I would hope that when we use the phrase we could reach an agreement that certain reserve capacity ought to be factored in as not being excess. There were comments this morning that treated anything over peak as excess, and to me excess is a pejorative term, and I think in every case we ought to stress that a reliable reserve is certainly not in my judgment excess capacity.

And I note, in Connecticut we have a seeming anomaly. There seems to be a lag in public perception. There's a great concern, and I think it has legitimate basis, about the possibility of excess capacity, while in fact last summer and this summer we're facing serious crunches in energy supply, serious strains. We are really at certain times during this summer and last summer using every kilowatt of capacity we can muster.

It's a seeming anomaly, and of course when these plants come on line next year we expect a big increase in capacity, but that will be very quickly eaten up. So your concern with the possibility of shortages is absolutely valid despite that seeming problem of excess capacity in the very short term.

And finally, I would only recall your remarks quoting Harry Truman about the heat in the kitchen, and mention that when the heat is turned up it often gets people jumping around pretty well. It's not all bad. Regulatory toughness, if you will, or scrutiny, regulatory skepticism, and jaundiced views of past performances are I believe causing a considerable amount of creative effort on the part of utilities to search for alternate new sources of power, creative financing schemes, and I'm reasonably optimistic about the future.

I don't think it's just a question of coming to an impasse. People are moving and moving very imaginatively to meet this new world that we're facing in the eighties and nineties.

Thank you.

[The prepared statement of Mr. Downey follows:]

TESTIMONY OF JOHN T. DOWNEY

BEFORE THE UNITED STATE SENATE COMMITTEE ON ENERGY AND NATURAL RESOURCES

JULY 23, 1985

"POTENTIAL FOR SERIOUS REGIONAL SHORTAGES OF BASELOAD GENERATING CAPACITY IN THE EARLY 1990'S"

Senator McClure, honorable members of this committee, good afternoon.

My name is John T. Downey and I serve as Chairperson of the Connecticut Department of Public Utility Control (DPUC). The DPUC regulates the state's privately owned electric, natural gas, telephone, water, and cable television companies, as well as intra-state trucking. We are charged to ensure that our people receive adequate service at reasonable rates.

I am privileged to participate in the discussion of questions of vital importance to Connecticut, and New England, as well as many other states and regions --- The possibility of widespread power shortages in the 1990's and what must be done now to avoid their occuring.

Connecticut is an industrial state with strong emphasis on key defense industries. The roll call --- AVCO, Pratt & Whitney, Sikorsky, Electric Boat --- demonstrate Connecticut's importance to our national defense, and the importance of the defense industry to Connecticut's economy. Economic development has been the foundation of State policy for at least a decade and, as we know, an adequate and affordable supply of electricity is critical in sustaining such development.

We have two major investor-owned utilities in Connecticut, which together account for some 93% of retail sales --- The Connecticut Light and Power Company (C L & P) and The United Illuminating Company (U I).

C L & P serves most of the State, including some 860,000 residential customers while U I serves the greater New Haven & Bridgeport area & provides service to approximately 260,000 households.

The fuel mixes of these two utilities are quite different.

For C L & P, over 55% of its electrical energy is generated by nuclear power, 25% from oil and 12% from coal.

United Illluminating today is dependent almost entirely on fossil fuel. (It may be of interest to note that U I's recent conversion of its 410 MW Bridgeport Harbor Plant from oil to coal reduced U I's dependency on oil from 93% to something in the neighborhood of 63%).

For the state as a whole, the electrical generation mix breaks down as follows:

57%	fossil fuel
41%	nuclear fuel
2%	hydro

Diversification of our energy mix is State policy, fixed in Statute.

We never forget that Connecticut is part of New England and that our energy fates are intertwined with the 5 other states which comprise the region —— and indeed many of us see our good neighbors to the North in Quebec and the Maritimes as sharing regional energy concerns. The New England Power Pool is but one of the many ties that bind us together. Most of the utilities in New England are members of the New England Power Pool. The primary function of this organization is to enable the member utilities, which own over 99 percent of the electric generation in the six New England states, to provide service to their respective customers at a high level of reliability at a cost lower than would be the case if NEPOOL did not exist. NEPOOL itself is divided into two parts: an operating branch, known as New England Power Exchange (NEPEX) and a planning branch, known as New England Power Planning (NEPLAN).

NEPEX carries out the central activity of the Pool, by dispatching the electric generating units of all of its members as if they were part of a single utility. This enables NEPEX to choose from a much broader array of generating units, with differing costs of generation, than could any single utility. As the dispatch is done on a economic basis (least costly power is dispatched first), the result of the central dispatch is that a more economic use of the generating units in New England is made than would occur if each utility generated and dispatched power solely for its own customers' use. The savings which accrue from this integrated electric network are shared among the member utilities.

NEPLAN conducts a wide range of studies and carries out other planning activities for NEPOOL. By scheduling and coordinating outages of generating units for routine maintenance, NEPOOL provides coverage to member utilities during what would otherwise be capacity deficient periods. NEPLAN also conducts regional load forecasting and planning for future generation requirements. Although the Pool does not own or build generating units, it does recommend those types of units which it believes would best serve the region. The construction and ownership arrangements for new generation then rest with the member utilities.

In an effort to assist in focusing this hearing on the specific questions of interest, I have restricted my comments to answering the questions posed by your staff memorandum.

1. Q. WILL SERIOUS SHORTAGES OF BASELOAD GENERATING CAPACITY OCCUR ON INDIVIDUAL UTILITY SYSTEMS BY THE EARLY 1990'S?

A. Assuming timely completion of the two nuclear units presently under construction---Seabrook I (1150 MW) and Millstone 3 (1150 MW) (both scheduled to come on line in 1986)---New England is unlikely to experience serious shortages of baseload generating capacity thru the early 1990's.

The most recent NEPOOL forecast report, dated April 1, 1985, predicts that NEPOOL reserves, expressed as a percentage of load, will drop below the reserve margin of 22% by the winter of 1996.

Given present trends in demand and construction, it is prudent to anticipate that Connecticut and New England will require major additions to baseload generating capacity by the mid-to late 1990's. It should be noted that apart from the two nuclear plants mentioned above, no New England utility is currently committed to significant capacity additions.

Should either of these two plants fail to be completed in timely fashion, then New England may well experience serious shortages of baseload generating capacity by the early 1990's.

As for Connecticut's major utilities, The Connecticut Light & Power Company, serving roughly three fourths of our population, anticipates that without Seabrook its reserve margin could drop below the NEPOOL requirements by as early as summer 1992. The Company is vigorously exploring means of deferring that date.

The United Illuminating Company's situation in this as in other regards turns on the fate of Seabrook Unit I. If the plant is completed in timely fashion, U I should be in good shape as to capacity into the next century. Should Seabrook I not be completed in timely fashion the U I picture changes dramatically. The Company would then be facing on-going capacity shortages by the late 1980's. Indeed, the Company presently has a reserve only 11% above its most recent peak.

In summary, given completion of the two nuclear plants, factoring in power purchases under Phase I and Phase II of the Hydro-Quebec agreements, factoring in conservation, significant amounts of cogeneration, small power production, retrofitting existing plants, all favorable developments, Connecticut and New England will likely nonetheless need new base load generation by the mid-to late nineties. Given the lead time needed to bring on a large unit such decisions must be made now.

NEPOOL (as agent for its member utilities throughout New England) has negotiated an agreement with Hydro-Quebec involving the construction of 600 megawatts of new transmission capacity between the systems and 3 terawatt hours of energy per year to New England (for 11 years beginning in 1986) and is currently negotiating a Phase II agreement involving an additional 1500 megawatts of transmission capacity and 7 additional terawatt hours of firm energy to the region beginning in 1990.

2. Q. IF SUCH SHORTAGES OCCUR, WOULD EACH UTILITY FACED WITH SUCH A SHORTAGE BE ABLE TO PREVENT ACTUAL INTERRUPTIONS IN SERVICE BY OBTAINING ADDITIONAL SUPPLIES, SUCH AS COMBUSTION TURBINE GENERATION OR PURCHASED POWER?

A. New England utilities are members of the New England Power Pool (NEPOOL), which, through the centralized dispatching of the region's capacity provides back-up capacity to its members on a minute-to-minute basis. By virtue of interconnections with the power systems to our West and North (NY Power Pool, PJM, Canada), NEPOOL can also obtain needed power from other pools if available and on a short term basis.

Given sufficient money and a removal of prohibitions in existing federal legislation, it is possible that gas turbines could be built by individual utilities. Gas turbines, relatively inexpensive to build but expensive to operate are essentially peaking units, not baseload units.

3. Q. IN YOUR FORECAST OF ELECTRIC POWER SUPPLY, WHAT ARE THE ASSUMPTIONS RELATING TO THE RETIREMENT SCHEDULE FOR EXISTING GENERATING PLANTS?

A. While several of Connecticut's fossil fuel units are scheduled to reach the end of their economic lives within the next decade our companies are working to extend the useful lives of these plants.

Connecticut-based nuclear plants, the backbone of our electric generation are presently scheduled for retirement as follows:

Connecticut Yankee (582 MW):	2004
Millstone I (660 MW):	2006
Millstone 2 (870 MW):	2010

The owners are exploring ways of extending the useful lives of these plants as well.

However, for purposes of forecasting electric power supply, we use the current schedules.

4. Q. DO ELECTRIC UTILITIES HAVE AN INCENTIVE TO MINIMIZE THEIR INVESTMENT IN NEW CENTRAL-STATION GENERATING PLANTS?

A. Electric utilities share a public service obligation to ensure capacity sufficient to meet their customers' needs.

Traditionally, there has been an incentive to build new central station generating plants. Companies saw capacity planning as a management prerogative and proceeded to construct plants with a certain confidence that costs prudently incurred would be included in the rate base once the plant became "used and useful."

The harsh experience of the past decade and more and the myriad forces being brought to bear on companies' decisions seem to be impelling companies seeking to meet their obligations toward smaller (e.g. 400 MW), less capital-intensive baseload units, with shorter construction lead times. The effort is to reduce the consequences of miscalculation of load projections.

Prudent management is also searching for means to defer the need for additional baseload capacity---utilizing conservation, cogeneration, small power production, retrofitting of plants and the whole rubric of what we call integrated supply-demand planning. However, solutions which envision a future of decreased system reliability, scheduled brownouts, rolling blackouts or power interruptions are not acceptable to this Commissioner. Nor do I believe the public would welcome such a future.

Of one thing I'm certain: the social and economic costs of too little capacity far exceed the cost to the public of too much.

Another characteristic in current management thinking on baseload additions is determination of management not to move forward on construction of major base load units absent clear, unequivocal support from regulators, legislators, government and the public, for both the construction and the choice of fuel.

The danger here is of an abdication of responsibility, a shrugging of the shoulders---of allowing lead time to dwindle so that options, too, dwindle and disappear and solutions are not necessarily the best.

5. Q. IF SO, WHAT ARE THE FACTORS CONTRIBUTING TO THE INCENTIVE?

A. As stated above the harsh experience of the past decade and more.

The litany of woes has often been recited. These include the Arab oil embargo and the escalating price of oil, soaring interest rates for capital in a very capital-intensive industry; double-digit inflation, the dramatic drop in energy demand, which threw load projections and capacity planning off-track; environmental opposition; post-Three Mile Island safety concerns which cost in both time and money; the decline of the nuclear construction industry; the perception by some companies that regulators, government, perhaps even the public were now blaming "management" for decisions government or public had acquiecsed in or even encouraged and, most unkind of all, that regulators were beginning to modify traditional principles of rate-making in ways inimical to shareholders.

6. Q. TO WHAT EXTENT HAVE SO-CALLED 'RATE SUPPRESSION' DECISIONS BY SOME STATE PUBLIC UTILITY COMMISSIONS INCREASED THE RISK OF FUTURE SHORTAGES OF ELECTRIC GENERATING CAPACITY?

A. One person's "rate suppression" may be someone else's "protection of the consummers".

I believe in strict scrutiny of a company's plans and expenditures. When we find imprudency, we adjust a company's rates accordingly. Companies must be held accountable for their decisions impacting rate payers.

Prudency traditionally has been analyzed using some variety of the "reasonable person" standard; that is, a company's decisions are reviewed by judging how a reasonable person having at his disposition the facts known at the time of the decision would have acted.

I would oppose any shift in the definition of prudency which would permit post hoc judgments penalizing companies for events subsequent over which they could have no knowledge nor could exercise control.

Having said this, it must be recognized that the world is changing, regulation is changing and companies are well advised to develop flexibility to meet these changes.

Concepts such as rate phase-in of major capacity additions are gaining regulatory and public acceptance. In Connecticut we are seeing a shift in the definition of "used and useful" from meaning "in commercial operation" to "providing net benefits" or "net economic benefits" to customers. Integrated demand/supply planning is growing in acceptance. Around the country, the possibilities of introducting competition into some aspects of the business are being explored, consideration is being given to opening electric generation to non-utility owners, and perhaps of disaggregating the elements---generation, transmission and distribution---of integrated systems.

While no one advocates changing rules in the middle or even in the late stages of a game, we all must recognize that some of these games (projects) were begun so long ago, so many conditions have changed over time and rigid adherence to traditional principles can have consequences so inimical to the ratepayers, that some shifts are imperative. We all must adjust to necessary change, bearing in mind that a company operating over time on the brink of financial collapse is unlikely to provide customers either with adequate service or reasonable rates.

7. Q. WHO SHOULD HAVE THE RESPONSIBILITY FOR ELECTRIC POWER SUPPLY PLANNING, ELECTRIC UTILITIES OR STATE REGULATORY COMMISSIONS?

A. In my few years as a regulator I have seen a profound shift in the traditional relationship between regulators and regulated.

Until quite recently, the utilities guarded their managerial prerogatives vigorously: as the enfranchised provider of service to their customers, they felt they were the sole entitles which could and should decide how best to meet their obligations. The decisions they made about construction plans, contract negotiations for capacity and energy, financing arrangements, were all areas which the utilities believed rested with management. The regulators for the most part agreed and focused on the areas of quality of service and rate-setting, accepting company load growth projections. To be sure, planning decisions, construction plans, load growth projections and the like were reviewed but the reviews were either post hoc or the commission lacked the means to conduct in-depth analyses. During the past decade, however, events with which we are all familiar have taken place. In that time oil prices have risen tenfold and electric rates have risen proportionately as a consequence, and load growths slowed from seven and eight percent per year to near zero; in addition, and even more dramatically, the costs of construction for new generating facilities rose drastically. Plants designed to lower customer's rates had to be justified on other bases.

The utilities have also been faced with very high costs of money, which have placed a great strain on their abilities to operate in their traditional ways. In additon, the utilities have been severely criticized when projections made in the years past have proven to be less than accurate.

The upshot is that utilities now perceive utility planning as a riskier business than it had been, and one in which they would prefer to involve the regulators. This has been manifested in a number of ways, most particularly in their insistence on prior approval before embarking on construction of large central station projects which would require the expenditure of large amounts of monies and which carry with them considerable risk. No longer do the utilities insist on their rights of managerial prerogative; rather, in order to reduce the future possibility of disallowance of recovery of costs on projects, the utilities have decided that the public sector, especially the public utility commission, should participate in the decision-making and initial stages of planning which the utilities are undertaking. The view thus is that in a world such as ours, with the risks as great as they can apparently be, it is appropriate that major efforts which are designed to meet the future needs of the utility's customers receive the early blessings of the regulators.

The question, given good faith on the part of all concerned, is how best to develop our relationships in this changing world. How should regulators participate in the planning process? Should regulators be seen as partners in this process? Should regulators be decision-makers for the utilities? If so, to what extent? Or, on the contrary, should regulators adhere to their traditional roles? Clearly, we can't go back to the old relationship--nor should we hastily and casually blur the distinction between regulators and regulated.

To do so drastically alters the relationship between the two, and will lead to a very different role for the commission to play. Should I run the utility? I say, no! I was not hired or trained to run a utility. Unless we are free to review and determine prudency, projects which later prove not to have been in the best interests of the customers will nonetheless have their costs passed on to ratepayers, as the commission will have been fully involved in the process. The long-term consequence of this is that the management of the utility will no longer reside at the utility, but would shift to the regulating commission, and as such the PUC will have absorbed responsibilities though ad hoc processes which are not within its statutorily mandated duties. A shift of this nature involves a major policy decision on the part of the public at large, and if it is to be made should be clearly specified and declared through the legislative process. Meanwhile, the commission must continue to review and rule on an on-going basis all the decisions of the regulated utilities and to allow the utilities to chart their own courses of action in order to meet their franchise and corporate responsibilities. Having said this, I know that our roles are changing and evolving and must do so.

Clearly our commission cannot act today in the same manner as it acted several decades ago, when the major issue confronting the PUC's was how much rates should be lowered. Federal law, state law and state energy policy, and regulatory precedent establish the framework for our role. The PUC in this regard must establish the guidelines which enable utility management to decide how best to meet its obligations. And the public, through its government, after thoughtful analysis of options must give companies the "go-ahead" in terms of timing, size and choice of fuel for major capacity additions.

The CHAIRMAN. Thank you, Mr. Downey.
Mr. Keenan.

STATEMENT OF GERALD M. KEENAN, GENERAL MANAGER, ILLINOIS COMMERCE COMMISSION

Mr. KEENAN. Thank you, Mr. Chairman.

During the course of these hearings we've heard a number of people saying that something has to be done to avoid possible shortages of electricity in the mid-to late-nineties. Ironically, even as the committee will ponder this problem, many of the areas of the country are awash with electricity and will continue to be so for the next 5 to 7 years.

This surplus and the looming potential shortage are in my view caused by the same cause: An antequated regulatory structure which no longer fits the needs of electric customers or the electric utility industry. Continued reliance on this relic of the past will assure electric customers of periods of shortage and surplus. Further, prices of electricity under this regulatory scheme will be too high in times of surplus and too low in times of shortage.

In fact, it's interesting to take a parallel between the natural gas industry and the electric industry. There is a great surplus of natural gas in the market now, which has caused prices to plummet over the past 18 months. Yet, in areas of the country where we have great surpluses of electric supply, prices only rise. And I think that that at least gives us some idea about what the regulatory structure is doing in a time of surplus, making things operate as no other market would operate.

In the long run, both the utilities and their customers will be ill served by the maintenance of the present regulatory system. What I'm proposing is a reduction of our current reliance on the regulatory structure and a greater reliance on market forces to provide proper pricing signals to consumers and adequate incentives and disincentives to construction of necessary new generating capacity and the rehabilitation of existing capacity.

I submit that the market will provide better incentives for accurate forecasting than the best intended and designed rules developed by any regulatory agency. Further, a competitive market structure for electric generation, coupled with nondiscriminatory access to the transmission network, will ensure the most efficient and economical use of existing generation, lowering prices to electric consumers.

Utilities, while they were up here testifying before as a panel, complained—and they didn't use this word, but I'll characterize their statement—as being whipsawed by regulators, about ratepayers gaining when the utilities did things better than average and ratepayers not being affected when the utility did something was below par, was considered to be below par.

Whether or not that's correct, it's a common perception and one that certainly, from the statements made by those utility executives, influences the manner in which they view further capital investment on their part. A reliance on the marketplace will allow electric generation entities, whether they be subsidiaries of utilities or nonutility entities, to earn super-normal returns for efficiency and to be punished by the market at times when they either guess wrong and they've got capacity that they can't sell or they make fatal errors in not buying the right fuel or not conducting their O&M in a proper manner.

The changing technological and demand conditions in the past few years have dramatically altered the structure and costs of the electric utility industry. Assurance of the continued financial viability of the industry, maintenance of adequate levels of supply reserves and reliability, and the protection of the interests of residential and industrial consumers requires that we fundamentally reexamine the traditional power delivery institutions.

My testimony, which I will not go through all the way, proposes a menu of positive solutions to some of the basic problems facing the industry. The cornerstone of these suggestions is an alternative framework for the treatment of electric generating capacity which recognizes the incipient competitiveness of this market.

Greater reliance on market forces in the generation sector of the industry could correct one of the more critical deficiencies of traditional regulation, its inherent inability to match end user prices with economic costs of production. Briefly, the standard regulatory practices attempt to achieve equilibriums with the use of historic costing techniques to make the supply of electricity appear to match demand levels.

Regulators can use methods such as disallowing capacity or deferring its capital recovery. This only provides regulators with the illusion of achieving a competitive result. These are simply accounting treatments, which are poor substitutes for market discipline.

One legacy of the accounting solutions on which regulators are forced to rely is the unprecedented supply and demand imbalances facing regulators today. Traditional regulatory accounting requires that a generating plant be completed and in operation before a utility's rates can be changed to reflect the combined costs of its construction and operation.

For plants with long construction lead times and during periods when construction costs and interest rates are high, consumers are insulated from higher electric rates until the plant is completed. On about a $4 billion nuclear plant, almost one-third of the cost of that plant is capitalized interest.

No other industrial entity will save—let's imagine General Motors building a couple of hundred million dollars Saturn plant. They're going to reflect the cost of borrowing the money and the cost of building that plant in their cost for cars long before that plant is completed and putting out vehicles.

The electric utility industry is atypical in the manner in which that's grown up, and in many fashions it's atypical because the accounting rules and the accounting treatments that grew up in this industry are the result of the fifties and sixties, when the average cost of each new kilowatt that came on line as generation was lower than the average cost of the entire system.

Now we have turned that on its head and we're still using the same regulatory accounting treatments to deal with the capacity as it comes on line. By preventing the pricing adjustments which track the increasing cost of electricity production from being passed on to consumers as they occur, the critical role of price as a signaling mechanism between consumers and producers is destroyed. This lack of information restricts the consumer's ability to influence the utility's decision to construct the capacity.

In a plant in which there is no CWIP allowed, that takes 12 years to build, that costs $4 billion, all during the time that the plant is coming on line, except for normal O&M increases, the real cost of that construction is never reflected in the customer's rates. And then you suddenly have this giant shock which tells the customer that, as prices go up, they should constrict demand.

And yet, that construction of demand comes at the exact time when the surplus of generating capacity comes on the market. So we've got an accounting and a regulatory treatment that doesn't match the actualities of the marketplace.

The corrective measures that we propose are designed to alleviate the problem by improving the flow of information between customers and producers in the market. In addition, it also would allow the use by the electric generating entities, whether they be subsidiaries or affiliates of utilities or just wholly independent entities that choose to get into the business, of a variety of financing techniques which are not available to electric utilities.

Electric utilities live with the financing vehicles, basically with the financing vehicles that were available to companies in the forties and fifties. If you were to take a build a plant on a partnership basis, the flow of benefits available to the partners in the venture in the first 4 or 5 years of operation would not require a return on capital at all, in the same way a real estate partnership works. And that fact alone is one of the things that makes cogeneration and small power production so attractive, because the financing vehicles that are available are substantially different than those that are available to public utilities.

Briefly, the key elements of the program are: First, in the short term, implementing incentive rates to market additional energy to industrial customers or to other customers outside the service territory;

Second, by adopting centralized dispatch within a State first, to integrate and utilize a State's capacity resources more fully, so that utilities stop looking at themselves in terms of their own entities and what they need, as opposed to what a larger geographic area needs. Some States have done that efficiently. PJM has done that on a more than one-State basis, but there's still a lot more that can be done.

Third, to develop power brokerage and auction markets among utilities to facilitate the competitive allocation of power requirements among producers. The Southwest bulk power experience that FERC has been conducting and the Florida brokerage system are two examples of some of the possibilities there.

Another thing is to allow the development of interstate compacts among regulators to more fully exploit the benefits of an integrated generation market. One of the opportunities there might be, for example, the use of a centralized dispatch for a region.

Another thing that's essential is to require non-discriminatory transportation or wheeling of power between individual customers and producers, to eliminate unjustifiable regional differences in price, thereby beginning the creation of a national energy market. In its investigation the committee I suggest should give special consideration to the problems of developing and building new transmission facilities.

One of the greatest impediments to the building of a more national market in electricity is the problems that are faced in designing and building new transmission facilities. I suggest that one model the commission might consider is the oil pipeline model.

Oil pipelines are not public utilities. They also do not have the power of eminent domain. They don't have the rights of condemnation, nor do they need approval from utility regulators to build their facilities. If they make a dumb mistake and build a transmission facility that nobody wants to use, the investors eat it. If they make the right decision, there is regulatory oversight by the FERC, although it's jumbled somewhat by the Williams decision.

And I think that the oil pipeline thing may provide a basis for the more efficient building of transmission facilities where the investors take the risks, and if there is a need for that power market it shouldn't fall on the local utility to close a bottleneck. And when it doesn't fall on the local utility, it shouldn't fall on the shoulders of the public utility commission to decide one way or another whether it's used, because the ratepayers will not bear the burden one way or another.

Another point of the plan is to unbundle the rate elements so that they can be priced separately, consistent with the requirements of a more competitive industry structure.

Eighth, we should relax the regulatory controls over generation investment that is subject to effective competition, thereby promoting a diversity of generating investments. In other words, if a company wants to go out and risk a few hundred million dollars among friends to build a 300-megawatt plant that isn't going to sell any electricity to anybody, be my guest.

Don't ask the ratepayers to pay for it, but if they want to make the investment they shouldn't have to go through 27 different regulatory hoops, utility regulatory hoops, in order to get permission to build the plant. Other regulatory things, such as siting and other things, are probably necessary and should be put into place.

Ninth, we should permit specialized agreements with individual customers which reflect the individualized circumstances to increase both long and short-term energy sales.

And lastly, we should encourage the development of spot and futures markets to increase options for capacity expansions and to improve the flow of market information.

Implementing the program or something like it will create a far more visible market for electricity and—excuse me, a far more viable market for electricity and its alternatives. The market will not only facilitate the marketing of power generated by traditional methods, but will also promote alternative generation sources, including conservation. The diversity of supply will promote the adoption of least cost strategies, increased reliability levels, provide appropriate market incentives for the development of safer and more efficient technologies.

Thank you, Mr. Chairman.

[The prepared statement of Mr. Keenan follows:]

TESTIMONY OF

GERALD M. KEENAN
GENERAL MANAGER
ILLINOIS COMMERCE COMMISSION

BEFORE THE

COMMITTEE ON ENERGY & NATURAL RESOURCES
UNITED STATES SENATE

JULY 23, 1985

Mr. Chairman, members of the Committee, I am Gerald M. Keenan, General Manager of the Illinois Commerce Commission. The Illinois Commerce Commission is the public utility regulatory agency in Illinois. I am again pleased to have the opportunity to testify here today on the electric power industry.

Many of the witnesses today will be urging the Congress to take action to avoid possible shortages of electricity in just ten years. Ironically, even as this Committee ponders this problem, many areas of the country are awash with electricity and will continue to be for the next five to seven years. This surplus and the looming potential shortage are caused by the same cause - an antiquated regulatory structure which no longer fits the needs of the electric utility industry. Continued reliance on this relic of the past will assure electric customers of periods of shortages and surpluses. Further prices for electricity will be too high in times of surplus and too low in times of shortages. In the long run, both the utilities and their customers will be ill served by maintenance of the present regulatory structure. What I am proposing is a reduction of our reliance on the current regulatory structure and a greater reliance on market forces to provide proper price signals to consumers and adequate incentives and disincentives for the construction of necessary new generating capacity and the rehabilitation of existing capacity. I submit that the market will provide better incentives for accurate forecasting than the best intended and designed rules developed by any agency.

Further, a competitive market structure for electric generation, coupled with non-discriminatory access to the transmission network, will ensure the most efficient and economical use of existing generation, lowering prices to electric consumers.

Changing technological and demand conditions have dramatically altered the structure and costs of the electric utility industry. Assurance of the continued financial viability of the industry, maintenance of adequate levels of supply reserves and reliability, and protection of the interests of residential and industrial consumers requires that a fundamental reexamination of traditional power delivery institutions occur.

This testimony proposes a menu of positive solutions to some of the basic problems facing the industry. The cornerstone of these suggestions is an alternative framework for the treatment of electric generating capacity which recognizes the incipient competitiveness of this market. A greater reliance on market forces in the generation sector of the industry could correct one of the more critical deficiencies of traditional regulation -- its inherent inability to match end-user prices with the economic costs of production.

Standard regulatory practices attempt to achieve equilibriums with the use of historic costing techniques to make the supply of electricity "appear" to match demand levels. Disallowing capacity, or deferring its capital recovery, provides regulators with the illusion of achieving a competitive result. Accounting treatments, however, are poor substitutes for market discipline.

One legacy of the accounting solutions of the past is the unprecedented supply/demand imbalances facing regulators today. Traditional regulatory accounting requires that a generating plant be completed and in operation before a utility's rates can be changed to reflect the combined costs of its construction and operation. For plants with long construction times, and during periods when construction costs are increasing, consumers are insulated from higher electric rates until the plant is completed.

By preventing price adjustments which track the increasing costs of electricity production from being passed on to consumers as they occur, the critical role of price as a signalling mechanism between consumers and producers is thus destroyed. This lack of information restricts the consumer's ability to influence the utility's decision to construct the capacity.

The corrective measures proposed are designed to alleviate this problem by improving the information flow between consumers and producers in the electricity market. A ten point program is recommended which relies heavily on market channels to facilitate the orderly marketing of electricity during periods of ample capacity and which provide consumers with enough price signals to permit them to influence future capacity construction.

The key elements of the program are:

- Implementing incentive rates to market additional energy in short-term industrial processes.
- Adopting centralized dispatch to integrate and utilize a state's capacity resources more efficiently.
- Developing power brokerage and auction markets to facilitate the competitive allocation of power requirements among producers.

- Realigning regulatory responsibility between the FERC and state commissions to promote more consistent and equitable regulatory policies.

- Developing interstate compacts among regulators in regional areas to exploit more fully the benefits of an integrated generation market.

- Requiring nondiscriminatory transportation (wheeling) of power between individual consumers and producers to eliminate unjustifiable regional differences in price, thereby creating a national energy market.

- Unbundling electrical rate elements so that they may be priced separately, consistent with the requirements of a more competitive industry structure, transportation (wheeling), and reliability of services.

- Relaxing regulatory controls over generation investment that is subject to effective competition, thereby promoting a diversity of generating investments.

- Permitting specialized agreements with individual customers, reflecting individualized circumstances to increase both short and long-term energy sales.

- Developing spot and future markets to increase options for capacity expansions and market information.

By implementing this program, a far more visible market for electricity and its alternatives will develop. This market will not only facilitate the marketing of power generated by traditional methods, but will also promote alternative generation sources, including conservation. This diversity of supply will promote the adoption of least cost strategies, increase reliability levels, and provide appropriate market incentives for the development of safer and more efficient technologies.

APPENDIX ONE

The Material contained in Appendix One was Originally Presented by Illinois Commerce Commission Chairman Philip R. O'Connor to The Select Joint Committee on Public Utility Reform of the Illinois General Assembly in February, 1985

I. THE POWER ADEQUACY WINDOW: LARGE SCALE POWER ADDITIONS HAVE EXCEEDED DEMAND

Today the electric utility industry is characterized by abundant levels of generation capacity. Depending on future load growth, this situation may or may not be temporary. At the present time, however, reserve margins are more than sufficient. This power adequacy window resulted from the combined effects of several circumstances. Among them were major surges in inflation and recession, accompanied by substantial increases in capacity costs and the real (but regulatory derived) price of electricity. In response to higher prices, electric customers are adopting energy saving technologies, thus further aggravating the present supply-demand imbalance.

The current situation of high prices and large amounts of available capacity cannot be reconciled with our normal views of how a market should behave. Prices in regulated industries usually do not respond well to changes in supply and demand. Consumers receive price signals that indicate scarcity at a time when supplies are more than adequate; likewise, regulation holds prices down in periods of shortage. A method to improve the efficiency of these prices in periods of surplus or shortage is the introduction of competition in the generation sector of the industry. Under this approach, the role of the regulator will be limited to protecting consumers from the monopolistic power of the local distributor; capacity additions, generation practices, reliability levels, and wholesale prices would all be policed by a much stricter guardian - the competitive marketplace.

This testimony provides a ten step progressive framework for the realization of market benefits. Section II describes currently available regulatory solutions to the problem of power supply additions which have not coincided with growth in demand for electricity. These approaches include traditional rate base methods and the more modern regulatory approach of phase-ins. These traditional regulatory solutions are shown to be useful but inadequate because they do not address the supply-demand imbalances. Rather, they produce price signals which have little or no resemblance to those that would be derived in a competitive environment.

Section III presents an alternative framework for dealing with the inadequacies of our current system during the present power adequacy window and in the future. The section describes the details of a ten step program for efficient capacity utilization and future planning. Implementation of the program simultaneously realizes the benefits of a competitive market for generation yet removes none of regulation's control over the abuses of monopolistic distribution companies. Some of these steps have already been partially accomplished; others require fairly extensive groundwork before they can proceed; all promise benefits to consumers -- whether they are adopted in concert or individually. In any case, changing circumstances may make such responses inevitable.

In Section IV the benefits of this alternative framework are described. The resulting competition would yield efficient, market-derived price signals for specific utility services. These signals will provide customers and electric power generators with the information necessary to insure a balancing of demand and supply. Further, price stability and predictability will better guarantee that correct decisions are made regarding the use and generation of electricity in both the short-and long-run.

II. REGULATORY SOLUTIONS: DISALLOWANCE, INCLUSION, OR DEFERRAL

The problem of large scale additions of generating capacity not coinciding with increases in demand creates fundamental problems. The traditional regulatory treatments of this problem usually take three forms -- disallowance of all or part of the asset from inclusion in the company's rate base, immediate inclusion of the asset in the rate base, or a phase-in of the asset into the rate base over a specific time period.

Support for the disallowance option arises from the long standing regulatory criteria of "used and useful". Under this doctrine, utility companies are denied the opportunity to earn a return on any asset which is not considered used and useful in providing service to the ratepayers during the test year, upon which rates are based. When a utility has a large reserve margin, the used and useful doctrine has sometimes been utilized by state commissions to exclude all or a portion of the company's electrical generation plant from rate base.

Unfortunately, disallowance does not provide a solution to the problem of a large amount of available generating reserve. Rather than directly addressing the capacity problem, its major purpose is to try to insulate customers from these high costs associated with the inclusion of the capacity in rate base. Even from this perspective, however, the disallowance option is less than adequate. Disallowances, by producing a non-performing asset, may well endanger the financial health of the utility. This increases the investor's perception of risk and therefore the utility's cost of capital, since both investors and lenders will extract a higher rate of return as a risk premium. Whenever the cost of money increases for a utility, an extra expense is added which is no different, from a consumer's viewpoint, than a wage increase for utility employees or higher coal prices. That means rate increases may well result from a commission's well-intended effort to hold rates down. Worse yet, the resultant electricity prices (rates) provide ratepayers incorrect signals regarding electricity availability. Consumers perceive, based upon the price increase which occurs, that electricity has become a scarcer commodity, when, in fact, the addition of large base load plants with low operating costs has actually increased the available supply of electricity.

The disallowance option has been proposed at times as a policy approach that would be used to keep a specific utility's reserve margin at some predetermined level. There are two serious and inadvertent problems with this approach. First, a specific percentage reserve margin may mean very little or be quite wrong without a very careful determination of what the mix of generating capacity should be -- what percent base load, what percent cycling units, what percent peak, what percent for each fuel type, what firing or dispatch order, what outage expectations, what options for purchase or sale of supply?

When a new power plant represents only a moderate increase in the overall utility rate base, the simple inclusion of the asset in rates, while uncomfortable and painful (as is any product price increase), does not present insurmountable obstacles. In cases where the plant would cause a large increase in rates, simple inclusion may not be a desirable alternative. This approach can cause significant and rapid increases in the price of electricity. The sudden large escalation in price forces a reduction in consumer demand. The corresponding reduction in sales causes the utility to request a rate increase which further suppresses demand. This phenomenon, known in the literature as a "death spiral," can continue with rate increases being concentrated over a smaller and smaller sales volume, unless the regulatory commission abandons its traditional approach to rate base regulation.

Option two, the inclusion option, can result in price signals which are distorted, as is the case with a capital disallowance. Again, consumers receive price signals indicating severe contractions in the supply of electricity when, in fact, the exact opposite has occurred.

Another modern regulatory solution to the inclusion-disallowance problem combines gradual inclusion with explicit price modification. This approach, often called a "phase-in", can provide improved price signals by gradually adding the cost of plant to rate base. In this way, lower rates are maintained initially at the expense of higher electric prices in the future. This practice has the advantage of being a superior signalling of supply conditions. Rates are prevented from rising at a time when the supply/demand imbalance is greatest, thus regulation-induced aggravation of the imbalance is prevented.

One obvious drawback of the phase-in approach is that the solution may be only temporary. Inevitably, rates will be forced to increase to offset the lower prices early in the project's life-span, since there are carrying costs on the deferred portion of the asset during the period of the phase-in. By this time, sufficient growth in electricity demand will have occurred so that a higher price signal is appropriate to reflect conditions normally warranting capacity expansion. Although phase-ins are superior to the disallowance/inclusion options when circumstances warrant, their effects are not without risk, and the resultant price signals, despite improvements, are far from sufficient.

Under each of these regulatory approaches, however, the problem of meshing supply and demand during the duration of the power adequacy window remains. The wave of the regulatory wand does not alter the fact that existing capacity does not balance with demand. Further compounding the problem are the intertemporal influences which destabilize electric prices through time as well. Consumers are encouraged to invest in electric saving technology (some uneconomic), demand is reduced over the long haul, and the under-utilization of potentially productive assets continues.

The pervasiveness of the problem is partially the result of regulatory solutions which statically focus on capacity and rely on a continued regulatory role. By definition, the regulatory process is supposed to yield the benefits of a competitive market. These benefits arise largely from the market's price signalling ability. Unfortunately, the price signals resulting from the regulatory solutions described above are wholly inadequate. Static, regulation-derived price signals cannot address the dynamic changes in production processes and supply/demand conditions.

Ambiguous price signals discourage generation efficiency on the part of suppliers and insulate them from consumer pressure. Utilities have inadequate incentives to adopt newer technologies which allow for smaller and more diversified capacity additions. In essence, the problem is one of information processing; the regulatory system is not capable of generating the accurate and timely two-way signals associated with a competitive market for generation. The following section describes a systematic program of market reordering designed to correct this situation.

III. TEN STEPS TO EFFICIENT CAPACITY UTILIZATION: THE COMPETITIVE MARKET OPTION

The regulatory framework supposedly exists to simulate the process and effects of a competitive market. It is reasonable to ask, however, whether it is possible to make a transition from an electric industry characterized by pervasively regulated monopolies to one in which the price of the electric product is largely a function of supply and demand.

While such a transition cannot be made overnight, it is likely that a step-by-step approach could reach the goal of an essentially competitive market in electricity. The beauty of the following ten step program is that it has a logical progression that can be halted and restarted at any point as circumstances warrant.

Although the ten steps may have some overlap with one another, each can be identified. For many of these steps, there is a potential legislative response by the General Assembly in the course of the review and revision of the Illinois Public Utilities Act.

A. One: Incentive Rates

A first step in the more efficient exploitation of a utility's capacity is the use of incentive rates. Since generating capacity is added in very large discrete segments, utilities often experience periods where the demand for electricity is less than the available supply. The use of incentive rates may help to fill these voids.

As discussed in some detail in another Sunset Monograph, incentive rates enable industrial customers to increase electricity purchases in the short-run without a concomitant increase in long-run costs. The rates are designed to be lower than otherwise applicable tariffs (thereby increasing demand), while still above a utility's variable cost of production. This latter requirement assures that the increase in sales positively contributes to the recovery of the utility's fixed capacity costs and thus benefits all ratepayers. An incentive or economic development rate must not represent either a subsidy from some customers to others or cause an increase in peak usage. Rather it should add demand incrementally in off-peak periods.

The flexibility afforded by these types of rate design promote the efficient use of otherwise idle capacity by permitting short-run increases in demand to match short-run surpluses of capacity. Experimental versions of these tariffs have already been put into effect in Illinois and are yielding the benefits of superior price signalling.

B. Two: Centralized Dispatch

Another method of gaining greater efficiencies in the production of electricity is through the use of centralized dispatch. Electric generating units exhibit various operating efficiencies depending upon vintage, fuel type, design, and environmental controls. Minimizing the cost of production at any point in time requires that the least cost (most efficient) combination of generating units be used for supplying power needs.

In a central dispatching scenario, utilities in a state or region join together and commit their generating facilities to be operated from a single control facility. Central dispatch ranks (and commits to production) generating units in the most efficient manner, without regard to company ownership. For example, by considering an entire state's generation capabilities as if there were a single utility serving the State, central dispatch serves the state's load at the least possible cost. Furthermore, central dispatch provides market-like incentives by rewarding efficient plants (and plant owners) with high utilization rates, and penalizing inefficient plants by limiting their output only to those periods of very high demand. In either event, centralized dispatch exploits key opportunities for a more efficient use of a state's generating capabilities and represents a step towards market based dispatch. The General Assembly may wish to strengthen the ability of the Illinois Commerce Commission to provide for cental dispatch.

C. Three: Power Brokerage and Auction Markets

Another institutional structure that has the potential to increase generating efficiencies is the use of brokerage, or auction markets, for power. Unlike centralized dispatch, brokerage and auction markets make use of the advanced information handling capabilities of computers to facilitate market transactions between utilities.

In a brokerage/auction market, voluntary buy/sell agreements between companies occur on an hourly basis, allowing the most efficient generating units to be most heavily relied upon. Computers make available the information necessary to make a complex power market feasible. This type of market is currently operational between utilities in Florida.

Brokerage/auction markets represent a significant step toward competition in electricity and a substantial break from the past. The creation of an auction market -- utilizing available computer technology now at work in exchange markets ranging from stocks and bonds to commodities to natural gas -- would represent, at the very least, the psychological commitment to move away from rate base pricing toward market pricing. A brokerage/auction system of central control through central "market" dispatch (as opposed to the traditional design of regional central dispatch operations) would involve many buyers and sellers.

In the Sunset process the General Assembly, rather than mandating an auction market, can first of all authorize its creation and set the stage for it by permitting the Commission to establish a system of interconnected dispatch similar to that described in Step Two.

D. Preface to Steps Four and Five

For a system of central dispatch to have its full impact and ultimately allow auctioning/brokering to develop between central dispatch areas, the market should preferably be larger than a single state. This is desirable in the same way that moving to a statewide market is preferable to having each utility provide their generation needs completely.

In moving to a broader market providing greater diversity of supply and intensity of competition among generators (both centrally dispatched and brokered), there will need to be better coordination among states and with the Federal government. In each case, the realignment of regulation can start with Illinois and the Sunset process.

E. Four: Realignment of FERC Authority

The existing boundaries of regulatory authority within the State of Illinois between the states and the Federal Energy Regulatory Commission (FERC) is at best confused and at worst in conflict with technological reality. Although electric utilities, utilizing the same capacity, sell power to their customers and to each other, jurisdictional responsibility is shared by the FERC (wholesale) and state PUC's (retail). Since the states and FERC frequently adopt dissimilar regulatory and accounting policies, the industry and consumers are denied the benefits of consistent approaches. There seems little rationale for vesting in FERC authority over the rates paid by one class of customers, i.e., wholesale customers within the same state, while all other customers are served under tariffs approved by the state commission.

Currently, utilities pursue wholesale and retail rate increases separately, using different test periods, cost data, and allocation methodologies. The consolidation of all intrastate tariff jurisdiction within each state would assure that all prices are developed consistently and that all customers bear an equitable share of the utility's costs.

Aside from the necessity of state jurisdiction over intrastate wholesale bulk power sales, states also need to have authority to order and set rates for wheeling. Under the existing system, FERC has sole authority to set rates for power wheeling and has only limited authority to order wheeling. State authority to order wheeling is in dispute. As a consequence, utilities and their customers are denied the potential benefits of wheeling when a recalcitrant utility is involved, and regulators are unable to gather necessary experience with this innovative, cost-control mechanism (efficiency aspects of wheeling are discussed further below). The development of rational and informed regulation requires that the states have clear authority in the intrastate bulk power and wheeling markets.

The General Assembly could authorize the Illinois Commerce Commission to petition FERC to delegate to the Commission the authority to regulate the wholesale electricity market within the State. This authority would significantly enhance Illinois' ability to progressively establish centralized dispatch and/or brokerage/auction opportunities without Federal regulatory obstacles which could both delay the efforts and provide a bulwark for utilities against the rigors of competition.

F. Five: Interstate Compacts

Many of the reforms described above are premised on the fact that electrical production technologies transcend corporate and jurisdictional boundaries. Consequently, with dispatch and production decisions made "company neutral" through the use of centralized dispatch and/or market incentives, greater efficiencies in generation can be achieved.

Artificial boundaries will remain, however, if state commissions narrowly perceive the market for electricity as coterminous with state boundaries. The use of interstate compacts to develop regional marketing and regulatory cooperation could overcome this problem. Under a system of interstate compacts and brokerage markets, centralized dispatch centers in adjoining states could coordinate production decisions to exploit cost and load variations. Furthermore, as use of the transmission grid is increased through a breaking down of barriers to the wheeling of power, the geographic scope of those compacts (and correspondingly their potential efficiencies) can be expected to increase.

The National Association of Regulatory Utility Commissioners (NARUC) and the National Governors Association have recently endorsed the concept of regionalizing regulatory authority through the use of interstate compacts, thereby initiating the transition to more rational geographic structures. A general opening of electricity markets can be expected to accelerate regionalization trends. The General Assembly could authorize the Commission to negotiate and enter into interstate agreements on central dispatch and brokerage/auction systems.

G. Six: Wheeling of Power

A critical requirement in the market-based movement is the ability of producers of electricity to have their product delivered to consumers. Access is provided by the ability to "wheel," or transport, electricity through the integrated transmission system. Such power interchanges can occur between traditional electric utilities or between producers of electricity and specific customers in different areas.

A main benefit of wheeling is that consumers are no longer limited to a single supplier for their electric needs. Most customers are now limited to purchasing electricity from the electric utility serving their area. Under a framework which facilitates the transportation of designated generation to specific customers, arbitrary geographical differences in prices can be eliminated. Consequently, the assurance of transportation for producers and consumers will guarantee development of a geographically broad market for electrical power, thereby forcing market-based pricing across regions, supplanting the reliance on rate of return regulation which characterizes the current regulatory structure.

As previously discussed, the implementation of this option is partially dependent upon the adoption of a rational system of regulatory authority. In combination with other steps, however, it is possible that freer access to transmission facilities can be achieved. For example, FERC conditioned its approval of an experimental brokerage market for wholesale power in the Southwest on the requirement that participating utilities would open their transmission systems to each other's power. Incremental solutions such as this can be pursued at the state level as well.

A full wheeling system would include the following types of transport:

- utility to utility;
- utility to a specific customer in another utility's territory;
- non-utility electric power producer to a utility in another area; and
- non-utility electric power producer to a specific customer within a utility's territory.

Some will argue (from a traditional utility regulation standpoint) that allowing wheeling to specific customers within a utility's territory results in higher prices for the remaining customers since it leaves the undiminished rate base to be covered by a smaller customer base. Such criticism is misplaced because it assumes mandatory wheeling would exist in a vacuum and without the institution of the other steps in this ten-point program.

To the extent that the local utility were provided rate base regulation for its distribution and transmission system (since it is a monopoly as the only available transporter of power) and is required to rely on market pricing for its generating capacity, there would be no problem for the other customers. In fact, intrusion of lower priced electricity into the area would force the local utility either to lower its own prices or forego the opportunity to sell its own electrical power.

The General Assembly can provide the essential component of a competitive market by ensuring open and fair access to the transmission and distribution system.

Steps seven, eight, nine and ten involve specific efforts to carry through on the various levels of wheeling so as to protect non-wheeling customers, regulate prices of remaining monopoly transport activities, and encourage active market pricing of electricity.

H. Seven: Unbundling of Rates

Traditional utility pricing decisions commonly "bundle" several separate services into one tariffed offering. For example, prior to competition, telephone companies did not distinguish the variety of services provided in its monthly rate -- phone rental, inside wire, local service, and directory information. The advent of competition in the provision of some of these services required that they be unbundled from the standard package and offered and priced separately.

Similarly, the natural gas pipeline industry has traditionally priced natural gas and gas transportation together as one charge. Competition from alternate fuels and competition at the wellhead has now caused these distinct services to begin to be offered on an unbundled and separately offered basis. Competition in the electric utility industry can be expected to develop along a similar path.

Competitively unbundled electricity rates will probably consist of the following elements: demand (kilowatt level), usage (kilowatthours), transport (wheeling), and reliability. While the first two elements are included in traditional utility rate designs, the latter two fulfill the needs of a competitive environment. Consequently, as alternative energy sources and competitive institutional frameworks develop, public utility commissions and utilities must be prepared to address complex cost accounting and pricing issues associated with these new services.

The General Assembly, in recognition of the need in the near future for unbundled rates, could specifically authorize the Commission to set separate rates for different components of electric service, while retaining pricing oversight of monopoly activities such as transportation. Under this proposal, the Commission could gradually remove regulatory controls (which tend to keep prices higher than under competition) from competitive elements such as usage, demand, and reliability for specific classes or subclasses of customers as competitive alternatives develop over time.

I. Eight: Devolution and Diversity of Supply

The "regionalization" of the electric supply described earlier goes a long way toward creating a heightened level of competitive activity among generating facilities. Wheeling, centralized dispatch, and brokerage markets all result in an appropriate structure for the evolution to full competition and the extension of its benefits to all consumers of electricity. Just as there is a two-fold objective for a competitive electric market, i.e., market determined prices for electricity as well as market-based decisions on capacity addition and usage, there are also two essential elements in the movement towards competition in the production of electricity.

The first element will allow for true diversity of supply. From both a technological and economic standpoint there is certainly no reason to prevent supplies of electricity from entering a utility's system from a substantial number of sources. Among the potential sources of supply are:

- cogeneration facilities where steam produced for some process or manufacturing purpose is also used to produce electricity;

- waste heat captured from such facilities as oil refineries or grain dryers which can be used to produce electricity;

- small power producers using a variety of fuels and technologies (e.g., coal, hydro, biomass, and solar whose primary business is power production); and

- utilities in other states or regions prepared to sell electricity at favorable rates (the same utilities may also wish to purchase at other times).

Currently, Illinois has little operating cogeneration or other sources of supply since the existing monopoly system effectively permits only one buyer -- the local electric utility -- to purchase a producer's output. While the utility is obligated to purchase the electricity produced by the cogeneration, the price is set at the utility's avoided cost (which during an era of sufficient supply is quite low). Over the longer run, diversity of supply could take better root given a situation that allowed non-utility suppliers to sell electricity directly to customers (using the wheeling option) or sell electricity to both direct customers and utilities at negotiated, market-value prices (rather than at prices created by legislative or regulatory bodies).

A system which allows full diversity of supply could also result in the addition of electric generating capacity in relatively small increments as independent suppliers perceive the development of increased demand. This would help to alleviate the problems of temporary surpluses of capacity which occur when large discrete amounts of generating capacity are added by a utility.

The second element of a competition based supply system is devolution -- the movement of utility owned generating capacity from rate base regulation to competitive status. Devolution need not take any single form. There are numerous available approaches to devolving electric generating capacity from monopoly status to the level playing field of a competitive diversity of supply.

There are at least five available mechanisms which can be used to achieve partial or full devolution. Circumstances should dictate which are appropriate for any particular utility at any particular point in time. These mechanisms are:

1) All, or portions of, existing rate-based generating capacity could be designated as "devolved." That capacity, with regulatory approval, could be placed in a holding company subsidiary that would earn its return on investment through its ability to market the electricity it produces. A step in this direction was recently taken by Tucson Electric Co. and the Arizona Corporation Commission. In this instance, Tucson Electric was allowed to spin-off 20 percent of an operating plant and 100 percent of a plant scheduled to be completed in late 1985. Electricity generated from these units is sold to wholesale customers only. Although the plants are not included in rate base and are therefore out of the regulatory control of the Arizona Corporation Commission, FERC jurisdiction remains because of the wholesale nature of the transactions.

2) Utilities could make ownership deals with cogenerators or other third party power suppliers for the joint development of incremental capacity.

Currently, federal law limits utility ownership in such enterprises to a ceiling of 49 percent. Should devolution become an accepted approach of enhancing diversity of supply and competitive pricing, Congress might raise the ceiling.

3) Should there be growth in demand over time, recent difficulties encountered by utilities and the public with financing new large plants will tend to deter utility commitments to new, large generating plants. One option would allow utilities to make modest investment to improve the efficiency and productivity of existing plants. It would be possible, especially through incentive programs, for utilities to devolve the increased output into competitive status and market it in a diversity-of-supply scenario.

4) In the event power plants of any size are to be built by a utility, they might be done so in cooperation with utilities in other territories in a devolved ownership approach. A number of utilities would share ownership and then undertake to market the electricity within their own combined areas or into other territories.

5) New capacity now under construction might, in part or in whole, be devolved by the utility into competitive status. With proper financial structuring and wholesale pricing treatment, a utility with a new nuclear plant, for instance, might be able to "spin-off" a plant into the competitive market.

Devolution can follow carefully and logically from a program of diversity of supply. The General Assembly, if it wisely chooses to tap competition as a regulator of electric prices, could provide for measured movement toward competition among sources of supply by enhancing opportunity for non-utility suppliers and by creating, through devolution mechanisms, a level playing field that protects consumers and forces all suppliers to submit to the rigors of the market place.

J. Nine: Contracting and Off-System Sales

As noted in Step One: Incentive Rates, potential benefits for utilities and their customers can be achieved through temporary increases in sales. The use of incentive rates offers discounted prices to a class of customers based on some set of economic and/or consumption characteristics. While these tariffs should increase short-term sales, they still cannot meet the unique needs of individual customers. In this "specialty" market, the potential for additional sales may be significant.

The contracting option is designed to permit the development of specialized agreements between the utility and individual customers for both short-and long-term energy sales. Currently, tariffs and case law form the basis of a "social contract" between the utility and its customers which imposes, in part, an obligation on the utility to meet the current and future needs of a customer.

Under the contracting option, utilities and customers supplant this "social contract" with a separately developed agreement. Such agreements could provide individual customers with opportunities to purchase widely varying volumes of electricity without a concomitant obligation on the utility to stand ready to serve such loads in the future. In concept, similar service is currently available through "interruptible rates" which allow utilities to curtail service under certain conditions. The contracting approach is more general, provides greater flexibility, and promotes the aggressive marketing of capacity.

To facilitate the implementation of the contracting option and enable utility capacity to be related to specialized customer needs in ways beneficial to all parties, the General Assembly might provide for Commission approval of specific customer contracts and rates which ensure the coverage of costs and enhance the meshing of capacity additions and demand growth.

K. Ten: Spot and Futures Markets

The last component of an efficient institutional structure for electricity is the development of spot and futures markets. Each satisfies a separate need in the efficient supply of electric power and together are natural outgrowths of the environment created by the steps previously described.

A spot market allows consumers, either individually or represented by their distribution utility, to purchase electricity at market clearing prices. This opportunity will permit generating utilities to back down from more expensive plants and to purchase externally generated power to meet their native load. At the same time, a spot market provides low cost producers with an opportunity to market surplus capacity. The net result is a market equilibrium for electricity that balances supply and demand at price levels determined by the consumers of electric power.

The function of a futures market is to provide a market valuation of future capacity and supply conditions. With the alternative of purchasing future capacity at known market rates, utilities will be better able to evaluate and adopt a least cost strategy for their own system expansion. Furthermore, utilities will be able to "size" expansions more efficiently since a futures market allows them an opportunity to market future capacity surpluses.

The development of each of these markets not only has the potential to improve information about supply and demand, but also to provide additional intertemporal sources of both. By expanding the relevant market for producers and consumers alike, artificial barriers of time and company boundaries are eroded. This action will permit the discipline of a competitive market to require the most efficient utilization of generating capacity at the lowest cost to consumers with incentives unavailable under traditional regulation.

IV. BENEFITS OF THE ALTERNATIVE FRAMEWORK: MARKET-DRIVEN PRICES AND INCENTIVES

Implementation of the ten point plan for capacity utilization could reap rich rewards. The benefits of efficient pricing would far outweigh any transitional problems. Benefits will continue to accrue to consumers as each and every step of the ten point plan is carried out.

The benefits of this arrangement are multi-fold. Mandated competition will insure that prices reflect economic cost. No longer will consumers and generators be required to contend with price signals derived entirely via the regulatory process.

Capacity surpluses will be ameliorated via competitively derived price reductions -- not the distorted prices brought about by the regulatory process due to the imbalance between demand and supply.

Market-derived signals will guarantee that generation is conducted in an efficient manner, utilizing the most economical technology. The dictums of the marketplace will not tolerate inefficient generation practices. Only those suppliers who can operate competitively will survive. This process will yield electricity at the least possible price.

Stable and predictable intertemporal electrical prices will arise from spot and futures markets. Prices derived from these markets will provide consumers with sufficient information to make wise choices about appliance selection and future energy consumption.

Further, access to regional and national markets will insure diversified sources of supply. Diversification yields benefits in system reliability and price stability. Overall reliability levels will increase. No longer will geographic areas be at the mercy of price increases in a particular fuel used in generation.

The overriding benefit of mandated competition will be the elimination of regulatory problems with supply-demand imbalances.

Consumers will no longer be required to bear the brunt of price distortions arising from the power adequacy window.

Should the Sunset process in Illinois result in a movement to competition in electricity, it will be no less significant of a cutting edge for the nation than was the original Public Utilities Act in Illinois which is now under review.

The CHAIRMAN. Thank you all very much.

And the lack of questions is not a function of lack of interest in your testimony. It's a function of the hour of the day. We will submit some questions to you in writing, for response in writing.

I want to thank each of you for the time, not only spent in coming here, but also in preparing your testimony. It's obvious that much thought and effort have gone into the preparation of the testimony, and I think you have made it possible for the committee to focus on some problems in a different manner than we would have been able to do in the absence of your testimony.

Thank you each very much for your effort and your attendance at this hearing.

The hearing will recess until July 25, 1985.

[Whereupon, at 4:48 p.m., the hearing recessed, to reconvene Thursday, July 25, 1985.]

ELECTRIC POWER: POTENTIAL FOR SHORTAGES IN THE 1990's

THURSDAY, JULY 25, 1985

U.S. Senate,
Committee on Energy and Natural Resources,
Washington, DC.

The committee met, pursuant to notice, at 9:45 a.m., in room SD-366, Dirksen Office Building, Hon. James A. McClure, chairman, presiding.

Present: Senators McClure, Murkowski, Hecht, Evans, and Ford.

Also present: E. David Doane, senior counsel; Elizabeth Moler, counsel for the minority; and Benjamin S. Cooper, professional staff member for the minority.

OPENING STATEMENT OF HON. JAMES A. McCLURE, A U.S. SENATOR FROM THE STATE OF IDAHO

The Chairman. The meeting will come to order.

Today's hearing is the second session in the committee's 2-day oversight hearing on the potential for electric power shortages in the early 1990's. Early this week, on the first day of the hearing, a panel of economic forecasters presented predictions for the growth rate in electric power demand during the next decade. Their forecasts were within a range of 2.4 to 2.9 percent per year.

The witnesses generally agreed that during the 1990's, actual interruptions in electric service are unlikely. However, they emphasized that during the next decade there is potential for shortages of baseload generating capacity on many utility systems.

If demand turns out to be greater than expected, and generating plants currently under construction cannot be completed on schedule, then serious capacity shortages could occur. If that happens, utilities would be compelled to acquire supplemental supplies of power; such as combustion turbine generation or power purchased from other utilities. Regardless of the source, additional supplies would be very expensive and the added cost would be borne by the ratepayers.

Another point emphasized during the first session related to what may be a fundamental change in the electric utility industry. It can be described as the apparent reluctance of utilities to build new baseload generating plants because of the risk that when the plants are completed, State regulators will prevent the full recovery of the construction costs.

As one witness stated, electric utilities have virtually ceased ordering new generating capacity of any kind. That may not be a problem for the short term, given the adequate reserve margins that generally exist throughout the industry, but it could have serious consequences 10 years from now. At some point, new baseload capacity will be needed.

This morning we will hear testimony from witnesses representing the Department of Energy, other Federal agencies, and public-owned utilities. This afternoon we will hear from another group of economic forecasters whose predictions of future demand in some cases differ considerably from those I mentioned earlier. The final panel will consist of representatives of the nuclear power industry, the financial community, and industrial users of electricity.

Senator Ford, do you have any statement?

Senator **Ford**. I have no statement, Mr. Chairman. Thank you.

The **Chairman**. Senator Evans?

Senator **Evans**. No, thank you.

The **Chairman**. Our first witness this morning is Hon. Danny J. Boggs, Deputy Secretary, Department of Energy.

Mr. Boggs is no stranger to this group, either in his present capacity or his former employment here. We welcome you again.

STATEMENT OF HON. DANNY J. BOGGS, DEPUTY SECRETARY, DEPARTMENT OF ENERGY

Mr. **Boggs**. Thank you, Mr. Chairman, members of the committee. I want to congratulate you and the committee for this very fine set of hearings which is certainly offering a forum for the presentation of a very diverse set of points of view on the electricity situation and which is very thoroughly covering many of the areas under discussion.

There are certainly many details of the economic forecasts and the electric forecasts that have been presented, and those details are certainly fun to fight over. I'll be happy to try to answer questions on them. There certainly are many aspects that need to be looked at very closely—sales figures versus generation figures, weather adjustments, short-term events—and there are a lot of ways to mismatch figures. But I think those differences are not the key to the situation that we face.

I think when you sum it all up, it is clear that demand growth in electricity will continue. If there is no new building of powerplants or no additional sources of electricity, those lines on the graph will cross at some point.

At the same time, it is clear that today we have a large pipeline of construction from the 1970's which is gradually being worked off. We have very large reserve margins. For 1984 the margin was just under 34 percent, a figure that certainly was unheard of before 1975. And that margin will diminish only slowly for a few years, because we still have that construction pipeline.

The NERC projection for 1993 is about 27 percent. Certainly by the time you get out that far, there is considerable uncertainty in it. But the key point is that beyond that, there is essentially no new construction that is underway. One can quarrel about whether the ultimate time of shortage is 1992 or 1998, but it's clear that is the direction of effect if there is no change.

At the same time, we do have, in effect, some period of grace because of the current margins. Yes, plants do take some length of time to construct, but I don't believe that we have to measure our system on a 10- or 15-year leadtime. Doing so is, in effect, an admission of failure in another part of the system, because those leadtimes that we are now suffering have been the result of a whole concentration of factors that I think do not have to obtain in the future.

Thus, I would say that we are not necessarily, in effect, overdriving our headlights today; but we could well be doing so within a very few years.

I think it's also important to note that when we talk about excess capacity or large reserve margins, one of the reasons for that is the very large amount of oil-fired capacity that in effect we do not really want to use in the way that we did in the past.

In my testimony I indicate that last year we ran the oil-fired capacity at about 12 percent of its maximum, which was barely a third of what we did in 1973.

Last year we burned only about half a million barrels of oil per day to create electricity, which is down by 1.25 million barrels per day from where we were in 1978.

So simply to say that we have a lot of excess capacity, when in effect that excess is not new power plants, but is the old oil plants that I doubt that we want to go back to running at the capacity of the past, is something that's important.

I began by saying that I thought the details were not the key. The key to me is the system. How will we respond in the future? We know there is going to be uncertainty. I was struck, in attempting to skim all of the testimony, at how almost every forecaster, I think, saw about a 2-percent range that even that forecaster was unwilling to estimate between.

The low-growthers thought it might be from 0 to 2, and the high-growthers might think it was from 4 to 6, but everybody knew there was substantial uncertainty that we were going to have to try to cope with. It's clear we are going to need in effect an appropriate amount of new generation at an appropriate time, and how do we deal with that?

As identified in my testimony, the problem is that in effect, the public utility bargain which served the country well for many decades has begun to break down. That bargain in effect said that utilities would receive no excessive profits, but would be shielded from excessive losses. It was a form of price control, which yet did not have the common dangers of price control because of what was thought of as the public utility paradigm. It was an industry with no competition, with permanently declining costs.

As I said, that has begun to break down. We're seeing clearly that electricity is not necessarily a permanently declining cost industry. We're seeing all kinds of competition. And were seeing hindsight come in and break down that public utility bargain.

Yes, there have been large problems and there have been mistakes. There's plenty of blame to go around. But when the consumer asks, correctly. "Why should I pay for the mistake that the utility industry has made?" in effect the answer is "because they profited from the good decisions that were made." We all know the litany of plants where millions and billions of dollars of losses have occurred that have to be spread somewhere, but we don't usually think about the plants—and there are many—which have saved millions and billions of dollars, and those moneys have also flowed to the consumer.

And it is this breakdown in the system that I think has led us to the discussion that we're having today. We don't worry much, usually, about adequate capacity for aspirin or coverlets or office buildings or cars. We don't have hearings on "Will the rutabagas go out?" But the combination of this implicit price control and public utility accounting raises a problem which I believe is going to have to be solved by moving in one of two directions.

I mentioned public utility accounting in the sense that when you listen to the experts talk about the cost of electricity, it's not always the same thing as cost in other areas. If we accounted for automobiles the way we account for public utilities, when a company built a huge new automobile plant, the first year they would be able to charge $50,000 for the cars coming out of that plant, and after 20 years they would have to charge only $1,000. And that's not necessarily a sensible way to price.

In the future, it seems to me we have to move in one direction or the other. We must restore the public utility bargain so that companies, when they build approved plants, will be able to have confidence that they can recover the costs, or we will have to move in the other direction and allow more market-based pricing and profiting, so that a company, if it builds a new plant and takes the risk, will also be able to have the expectation or the opportunity for market-type profits.

I don't have a solution as to which is the best way to go. I think I can say with confidence that the current system, the way it has been operating, is unlikely to be viable from now through the year 2000.

I would conclude by saying that your witnesses have presented a wide variety of measures that can be used to avoid this impending collision. I would like to encourage you in your thinking about this, and the witnesses and the groups they represent, to try and keep those options open; not to promote a favorite panacea by closing off everyone else's potential solution.

I think we need to have those options available for choice by policymakers, by public utility regulators, and by utilities. It is too easy to say that X is not needed because we have Y available. But the reverse is also true. And if each interest group succeeds in promoting, or thinking that it promotes, its interests by knocking down everyone else's solution, we end up with no potential solutions in our menu of options for the future.

Mr. Chairman, that concludes my oral statement. I'd be happy to answer questions on my prepared statement or what I just delivered.

[The prepared statement of Mr. Boggs follows:]

STATEMENT

OF

DANNY J. BOGGS
DEPUTY SECRETARY
U.S. DEPARTMENT OF ENERGY

BEFORE THE

COMMITTEE ON ENERGY AND NATURAL RESOURCES
U.S. SENATE

JULY 25, 1985

Good morning, Mr. Chairman, and Members of the Committee. I appreciate the opportunity to appear before you today to discuss the Nation's long-term requirements for electric generating capacity, and the question of how to assure that those requirements are met in an economically efficient manner.

This morning I will offer a straightforward and, I hope, helpful view of these and other questions concerning electric demand, public utilities and economic growth. I would like to begin by commending the Committee for its decision to hold two days of hearings on this important topic. The focus of these hearings is to examine possible answers to the question, "When Will The Lights Go Out?" This is a complex issue, and it is encouraging to see that American utilities, regulators, and consumers are beginning to ask tough questions about our ability to meet future electric needs. Given the long lead time required to bring various types of new generating capacity on line, it is good to be thinking about this topic in advance.

In overview, we know that on a nationwide basis we have an oversupply of electric capacity in the sense that reserve margins are considerably larger than we are used to; most estimates indicate that those reserve margins will remain well above the usual level for most regions for some time into the future, though declining, given current construction, as we move into the 1990s. With that outlook, it's easy to say that we have plenty of time to consider the matter, and perhaps there is really nothing to be concerned about anyway. While each is entitled to his own views as to what may happen, I believe that the idea that America is simply never going to need new electric power plants any time in the next decade is simply not correct.

Concerns about America's ability to generate enough electricity to meet future needs are being heard with increasing frequency. For example, the New England Power Pool (NEPOOL) anticipates that record electric demand this summer, coupled with the likelihood of scant emergency power sales from New York State, could lead to a regional power shortage. "We don't want to scare anyone," says a NEPOOL executive, "but the situation is serious." If the 1982-1984 trend continues through the remainder of this year, electricity demand (net energy for load) in New York and New England will have increased approximately 11.5 percent since 1982, or about 3.7 percent per year. This compares with utility projections in 1983 of annual increases of 1.8 percent. Put another way, the region is getting about six years' worth of "projected" growth in just three. According to one NEPOOL spokesman, "Bermuda highs are a dirty word around here."

The controversy surrounding Long Island Lighting Company's (LILCO) Shoreham nuclear power plant has spawned a public debate there over competing forecasts of load growth, peak demand and reserve margins. Demand for electricity on Long Island has exceeded recent utility forecasts. In 1984, sales of electricity on Long Island were 13,577 million Kwh. This is 7 to 8 percent higher than the level projected by LILCO in each of its annual forecasts in 1980 through 1982, and 2.3 percent higher than projections issued as recently as the fall of 1983.

The New York State Public Service Commission reports that "LILCO will have insufficient generation to meet its peak load." Under the Commission's current projections, LILCO will probably have to resort to unusual steps, including voltage reductions. If conditions are worse than projected, the Commission reports, "stronger relief measures, including load shedding, may be necessary."

"The power shortage is not coming," observes one Long Islander, "it is here."

The question now is, what does this mean for America? Will our appetite for electric power in fact grow, outpacing our ability to build generating facilities to meet future demand? Will our utilities sustain or hinder economic growth?

Based on my reading of the data, I believe a strong case can be made for the following points:

- Demand for electricity will rise;
- The lights will not go out in this decade;
- Without new generating capacity, the lights, in my personal view, will start to go out sometime in the 1990s and will do so increasingly as the decade progresses;
- Thus, we need an appropriate amount of new construction, at an appropriate time; and
- The current regulatory system as it now operates will not necessarily encourage rational decisions about the new construction the industry needs, when it is needed.

The amount of appropriate new generating capacity, as well as the appropriate timing of new facilities, is determined through discussions between electric utilities and their regulators, mostly on the state and local levels. Thus, one might ask, "Why should the Federal Government be concerned with this?" While the Federal Government should not control or direct these decisions, it does represent the national interest in sound energy policy. When it appears that the regulatory system as it currently operates is going to prevent people from making decisions that make economic sense, whether it is a Federal regulation or local price control, then the Federal Government has a duty at least to speak out on this. Moreover, while we do not believe that the lights in fact are going to go out, we do believe that it is quite plausible that the United States could find itself in a situation where a crisis of inadequate capacity will be solved hastily by bringing on additional generating facilities that use gas and oil, which would add to pressures on these fuels.

The Administration wishes to encourage cooperative relationships among utilities, regulators and consumers.. In our view, such cooperation is the best means to assure electricity supplies consistent with future needs. Disharmony is undesirable and generally inefficient: Regulation in the darkness is probably not viable.

The Demand Debate

A starting point in most discussions of America's ability to meet future electricity is the attempt to understand the relationship of growth in electric demand to growth in real economic output, as measured by the Gross National Product (GNP). Between 1947 and 1973, electricity generation grew by about 2 percent for every 1 percent increase in real GNP. Following the price shock of the 1973 Arab oil embargo, the average annual rate of growth in electricity demand fell sharply: From 1973 to 1979, electric demand grew 3.3 percent. The ratio of the growth in electric demand to that of GNP fell as well, from about 2 to 1 to something more like 1 to 1, as real GNP grew at an average annual rate of 2.4 percent.

From 1979 to 1982, both economic growth and electric demand remained essentially flat (increasing at an annual rate of 0.01 percent and 0.17 percent per year, respectively). With two back-to-back recessions, this period provides virtually no reliable data for use in projecting long-term trends. At the time, however, the debate over the future of electricity demand was drawn more sharply.

On the one hand, many observers pointed to three years of stable demand for electricity and asserted that the Nation had entered an era of zero electric demand growth. On the other hand, some observers discounted the years of zero electric demand growth as the result of economic woes and concluded that with economic recovery we would be off to the races, with vigorous demand for electricity out-pacing real GNP growth once again.

In the past three years, a robust economy has challenged both versions of the conventional wisdom. Real GNP has increased in every quarter since the third quarter of 1982. Adjusted for inflation, GNP (1985 second quarter flash estimate) has increased 13.3% since 1982. This is the strongest economic recovery in 33 years. With eleven quarters of sustained economic growth, we have much more data upon which to base analyses and conclusions about electric demand and economic growth.

How has a revitalized U.S. economy influenced patterns of electric demand? Using weather-adjusted electricity demand figures developed by the Energy Information Administration and quarterly real GNP figures, Figure 1 compares, on a 36-month rolling average basis, the annual growth in electric demand with the growth in real GNP. On this 36-month average basis, the ratio of annual electric demand growth to GNP growth, adjusted for both weather and inflation, has remained steady at about 0.6 to 0.7 since February 1984. The ratio has been less than 1 since December 1978, except for brief periods in early 1981.

Another way of looking at this question is to ask if electric demand growth is likely to continue to be lower than GNP growth for some time. The historical data indicate that this is probable: On a 36-month rolling average basis, the real rate of GNP growth has exceeded the rate of electric demand growth by an average of 0.6 percentage points over the past eight years (Figure 2). In the absence of radical changes in price relationships, this pattern should continue.

Thus, to a great extent, one's forecast of the future demand path for electricity depends upon one's view of what will happen to real GNP. While there are, no doubt, some observers who project zero long-term real economic growth, I would argue that they are a tiny minority. My reading of the ongoing debate among various economists and forecasters would seem to suggest that the low end of projections of real long-term economic growth would be on the order of 2.5 percent; the long-term high would seem to lie somewhere around 4 percent. Thus, with real GNP growth between 2.5 and 4.0 percent each year, and the ratio of electric demand to GNP growth between 0.7 and 1.1, it would seem reasonable to project an annual electric demand growth rate between 1.7 and 4.4 percent over the next 16 years. Now that is a tremendous spread. Using that range, the Nation will need a total of 700 to 1,075 gigawatts of electric generating capability by the end of the century -- a net increase of 100 to 475 gigawatts over the 600 gigawatts in place in 1984. While dramatic price changes could throw electric demand out of these projections, long term electricity prices seem fairly stable.

Furthermore, some existing power plants are physically or economically obsolete, and still others are becoming so each year. Some 70 gigawatts of generating capability may be lost by the year 2000 due to retirements and aging. At least another 40 gigawatts are projected to become uneconomic, which means that they ought to be replaced, despite the fact that they may be operable. Thus, while net additional supply requirements at the turn of the century may be 100 to 475 gigawatts greater than the supply now in place, the need for new generating capacity could be 210 to 585 gigawatts. About 90 gigawatts is currently under construction.

While we currently have excess generating capacity, a large amount of this capacity -- 118 gigawatts, or nearly 20% of our total generating capacity -- is oil-fired, which is being used very little right now. As shown in Table 1, the capacity factor for oil-fired plants has fallen from about 38% in 1973 to less than 12% in 1984. This capacity can be utilized, but can be put to intensive use in generating electricity only at the expense of greatly increasing our oil consumption. While we are not projecting a need for any particular type of generation, it is nonetheless important to recognize the relationship of problems in electric generation to other energy goals.

The Collapse of the Public Utility Bargain

For many years, we have had in our society what might be characterized as the public utility bargain. Under this model, utilities and investors were told that they could not have "excess profits," but would receive a reasonable rate of return on their capital investments and would be protected from excessive losses.

Today, however, we are witnessing the collapse of this bargain, and with it the breakdown of the traditional model of a public utility. The current trend toward so-called "prudency" decisions or "used and useful" determinations does not appear to be consistent with the long-term needs of the system. Simply put, no utility will build a plant without some reasonable hope of recovering a fair return on its capital investment. If the present regulatory system as it currently operates will not allow this, it is untenable.

Consider just a few regulatory decisions over the past few years:

In June 1980, the Missouri Public Service Commission (PSC) denied rate base treatment of the Iatan 1 coal plant because the parent utility had "excess capacity," which the PSC equated with "imprudence." The thinking that went into the decision failed to stand the test of time: When the Midwest heat wave of 1980 demonstrated the plant's usefulness, the company was later allowed to put the unit in rate base.

In August 1983, the Pennsylvania Public Utility Commission (PUC) rejected assertions that Pennsylvania Power and Light (PP&L) had been imprudent in constructing the Susquehanna 1 unit, but ruled that the nuclear power plant was not "used and useful" because it represented "excess capacity." The PUC then ordered the utility to exclude from its rate base a percentage of its average rate base equal to the share of total capacity that was deemed to be in "excess" -- about 12%. This capacity was sold to another utility in a neighboring state. This regulatory decision, therefore, had the perverse effect of denying fuel savings to PP&L customers and providing the benefits of fuel savings to customers on other states.

The Massachusetts Department of Public Utilities (DPU) ruled in July 1984 that the prudency of planning or construction would no longer be considered relevant to rate base decisions concerning future plants. Rather, the Department ruled that the amount of future construction allowable in the rate base will be determined solely by the amount that is "used and useful" at the time of completion. The Commission defined "used and useful" to mean the economic value of the plant to consumers, relative to other investments that could have been made, or to no investment at all. In effect, the Commission stated that a utility was perfectly welcome to build a plant, but will discover the amount that can be put in rate base only if and when the plant starts operating. The extent to which a utility will be allowed "excess profits" if it makes a particularly good investment is the subject of ongoing debate.

Last August, the Montana Public Service Commission (PSC) denied any rate-base treatment of the Colstrip 3 plant, which had at that time been generating electricity for seven months, on the basis that the plant was not "used and useful." With perfect hindsight, the Commission ruled that customers could have been served equally well or better without the plant, had certain changes in Montana Power's operation, purchase, and construction practices been made. As bizarre as it may seem, the Montana PSC did not consider whether the utility's original decision to build the plant was prudent or not.

Finally, last April, the Pennsylvania PUC ruled that Pennsylvania Power and Light could place the Susquehanna II nuclear plant in rate base but could not earn a return on equity in its investment until net savings from the plant's operation equalled the increase in rates from placing it in the rate base. Out of a total rate request of $330 million (of which about $220 million was related to the Susquehanna II unit), the Commission denied a $160 million equity return. With a related decision reducing cost recovery from the plant by another $40 million, the PUC denied roughly 90% ($200 million out of $220 million) of the Susquehanna-related request. The basis for that ruling, according to the Commission, was that the unit represented "excess capacity."

It seems to me that one could draw a fairly straightforward conclusion from these decisions. With the possible exception of the Massachusetts DPU decision, the regulators are essentially saying that, even if there are real savings in operating nuclear (or coal) powered generation over oil-fired generation, the utility will not be allowed to receive the economic benefits from making that sound economic decision, but will definitely be penalized for any decisions that in retrospect prove to be unsound. I am not necessarily criticizing these decisions in terms of the law to which they respond. These decisions may be right; they may also be popular; but we must examine if we can have a viable future energy system with the reality and continued prospect of such decisions.

The Future

Today there are many voices saying, "Why should others bear the burdens of the mistakes of the utilities? After all, they made the mistakes, so they should be allowed to fail." Certainly mistakes have been made. But in the past, consumers received the benefits of a utility's good decisions. Moreover, in order to have a rational economic system, there has to be a match-up of benefits and burdens, of risks and rewards, or else no one will take risks.

Rate regulation as presently practiced may provide little incentive to utilities to undertake large capital projects, even if they are economic. Upon completion of a major generating facility, the best a utility can hope to do is earn a moderate, regulated return on its investments; if anything goes wrong during construction (including delays induced by regulations, rather than through a company's own actions), the utility's profit could be greatly reduced, or perhaps turned into a huge loss.

In essence, this could be considered a form of price control. In general terms, we are all acquainted with the evil effects of price controls, including misallocation of resources, shortages of supplies, and higher costs to consumers. Utility regulation has rarely been thought of as a form of price control. The reason is quite simple: Electric generating systems were long considered to be the paradigm of a public utility, with declining marginal cost curves and essentially no competition. These conditions, however, are no longer as true as they once were. As the assumptions underlying the system are beginning to crumble, the latent pressures of the past are beginning to make themselves felt -- and Americans are asking when the lights will go out.

Perhaps it is possible to return to the old system of public utility regulation, the "bargain" I outlined earlier, whereby "excess" profits are eschewed but a fair return on investment and some protection from the risk of huge, or excess losses, is provided in exchange. To get there from here, it is necessary for each regulator to take a hard look at the evolving "prudency" or "used and useful" decision making models and, perhaps, push them aside and return to the earlier system, with its "bargain" that provided stability and bore some relationship to rational principles of economic behavior.

Alternatively, there may come a time when some states may wish to move to an entirely new system with higher (market) rewards offered in return for higher risks, perhaps even one which may someday be termed "deregulation."

FERC has had some experiments with somewhat deregulated transfers of electricity. The State of Florida has been having some type of experiments and there is movement in Illinois along similar lines. We believe that in general there is a necessity to assess our situation. The different decision-making bodies have to work to make sure there is a correspondence of benefits and burdens, as well as risks and rewards.

This principle holds true among states as well as among a regulator, a utility and a customer. Some states may opt for more generating capacity at a higher cost; others may wish to add less capacity, at a lower cost. Those who guess wrong and build too much will clearly bear that burden. Those who guess wrong in the other direction and build too little should also bear the burden, rather than cast that burden onto other states by requisitioning power at a below-market price. Just as utilities have been affected and continue to be affected by decisions about new construction, your respective states have been and will continue to be affected by the kinds of decisions your regulators make.

Consider a case where one state is saying, "We don't need to build plants, the demand will not be there, we'll save the costs today," while another is bearing the costs and having too much capacity. Well, if the first state turns out to be wrong, and they need capacity and power and they have to get it from their neighbor, there is no reason whatsoever that they should expect to be bailed out at subsidized prices. We believe that the benefits from one type of strategy being adopted by a state have to be matched by their burdens if they turn out to be wrong.

Conclusion

In closing, I would like to assure you that my intent is not to offer threats or fully fleshed-out policy proposals to state regulators. I am trying to point out that what seems to be the conventional wisdom in many areas does not appear to square with reality and there are potentials for very large economic losses if it does not.

This concludes my prepared remarks. I would be happy to respond to questions from the Committee at this time.

FIGURE 1

Ratio of Elec. Growth to GNP Growth
(36–Month Rolling Average)

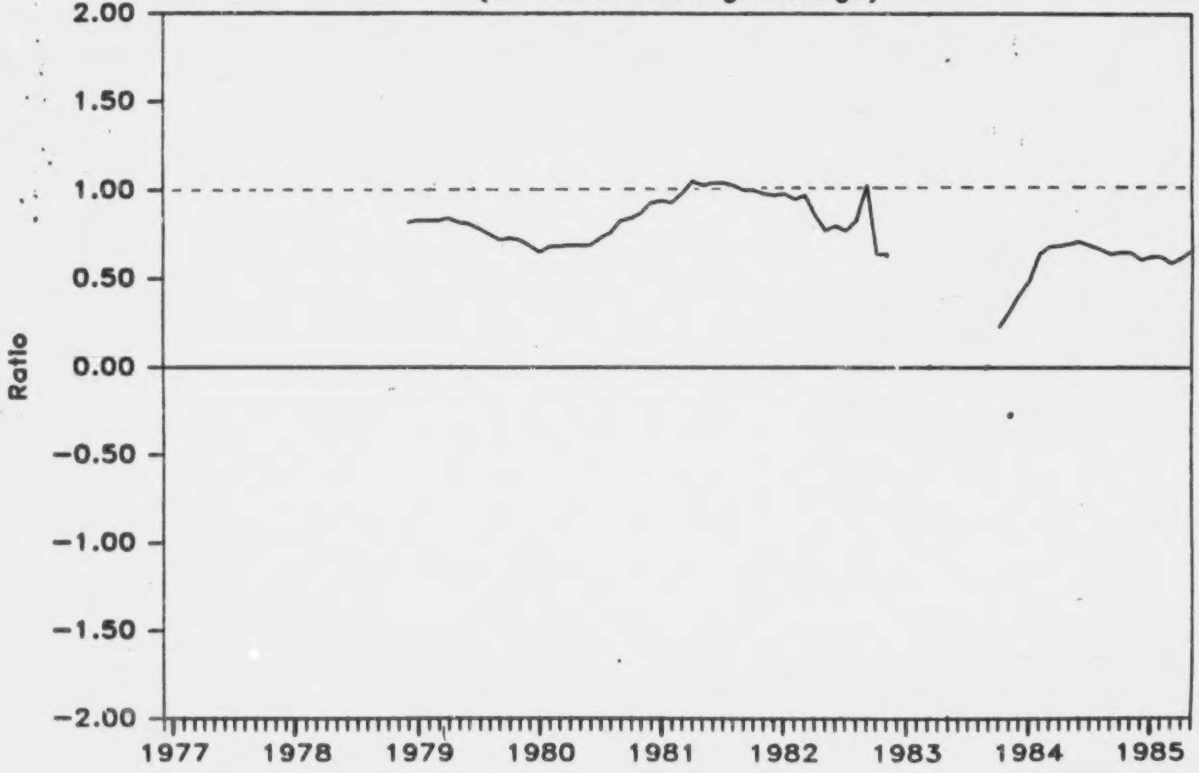

FIGURE 2

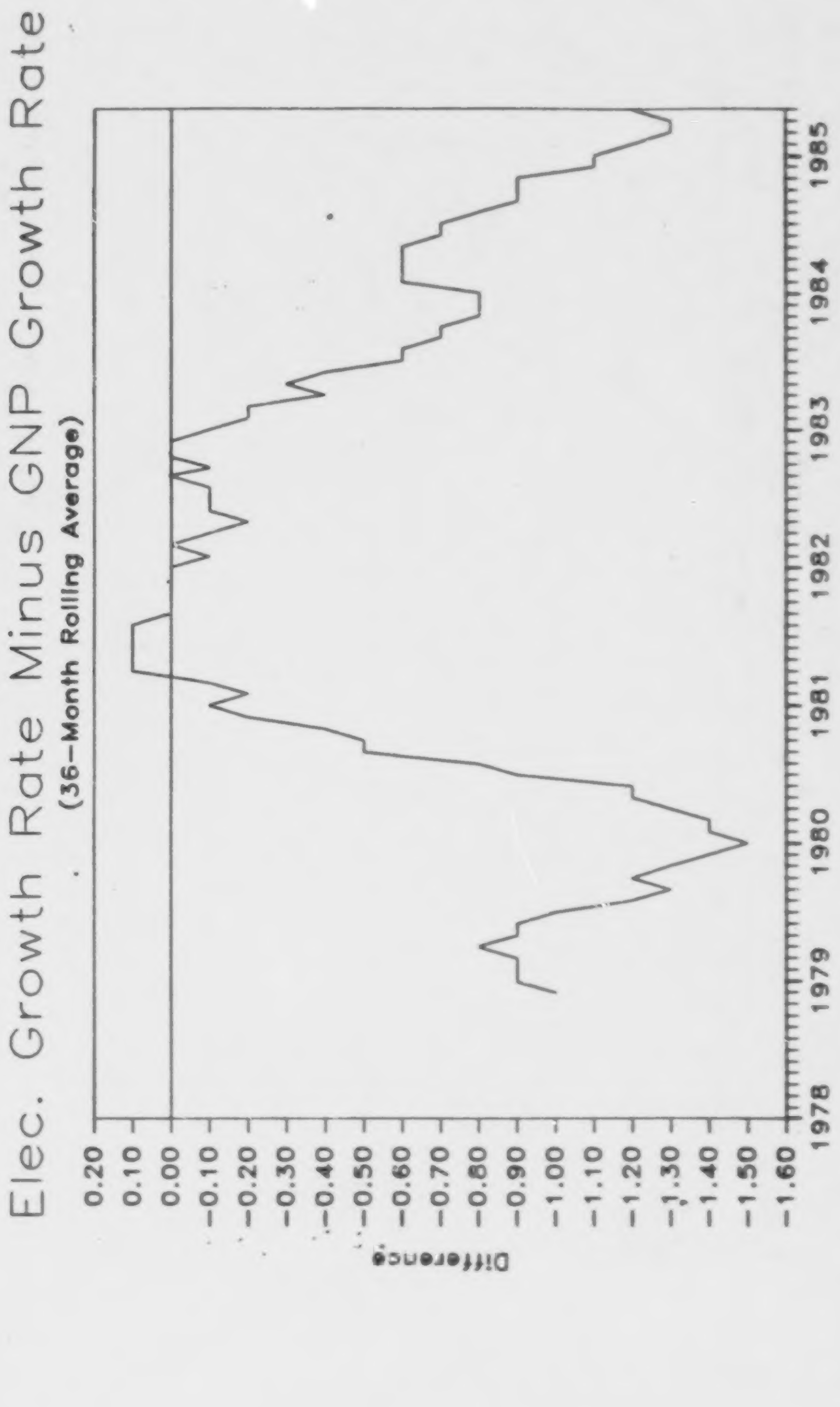
Elec. Growth Rate Minus GNP Growth Rate
(36-Month Rolling Average)
Difference
0.20
0.10
0.00
-0.10
-0.20
-0.30
-0.40
-0.50
-0.60
-0.70
-0.80
-0.90
-1.00
-1.10
-1.20
-1.30
-1.40
-1.50
-1.60
1978
1979
1980
1981
1982
1983
1984
1985

TABLE 1

NATIONAL AVERAGE CAPACITY FACTORS FOR ELECTRIC GENERATING UNITS, BY TYPE

Plant Type	Capacity Factor 1973	Capacity Factor 1984
Oil-fired	38 %	12 %
Gas-fired	51 %	35 %
Coal-fired	53 %	51 %
Nuclear	45 %	52 %
Hydroelectric	50 %	45 %

The CHAIRMAN. Thank you very much, Mr. Secretary. Your prepared statement will, of course, be made a part of the record in full.

You make reference to a number of case studies or examples of things that are really happening. And while you didn't make this point in the same way I perhaps am attempting to do, the statement on the bottom of page 2 and the top of page 3 refers to forecasts of power needs in the Long Island Lighting Co. service area as they relate to the controversy over the Shoreham nuclear power plant.

Do we witness in that situation the example of people who try to skew the forecasts in order to achieve a result which they desire with respect to the operation or nonoperation of that plant?

Mr. BOGGS. I wouldn't think so offhand, Senator. The forecast that is referred to there in effect was made by the utilities, so that I don't think they would have an incentive to low-ball it, which would be against their interest in operating their plant. I think, rather, it's simply an example that, particularly in smaller areas, but in larger ones as well, there's a lot of uncertainty.

If you recall in 1982, the general estimate of what was going to happen to the econony in terms of its growth and the strength of the recovery was much lower than what actually occurred. And I have not done an exhaustive analysis of that particular estimate, but I would not be at all surprised if that in good faith, relying on the conventional wisdom of 1982, they said, gee, we're not going to have much growth; the snow belt isn't going to do so well anyway, and we won't expect much more demand. Instead, of course, the national recovery has been quite vigorous and in fact the recovery in that area—in New York and New England—has been quite vigorous.

The CHAIRMAN. For the benefit of those who don't have your statement before them as I do, you outline that LILCO, in 1984, had actual sales that were 7 to 8 percent higher than the level projected by LILCO in each of its annual forecasts in 1980 through 1982, and 2.3 percent higher than projections issued as recently as the fall of 1983.

Are those figures percentages or percentage points?

Mr. BOGGS. I believe they should be percentages, unless my staff has misled me. But also in this context, I'm not sure it would make any difference, because you're operating on a very small change in base.

[The information follows:]

In 1984, LILCO had actual sales that were 7 to 8 percent higher than the forecasts of 1984 sales made in 1980, 1981, and 1982. The following table provides additional details concerning actual KWH sales and projections of such sales, over the past three years.

YEAR FORECAST MADE BY LILCO	FORECAST OF 1984 KWH SALES (x10^6)	ACTUAL 1984 KWH SALES (x10^6)	PERCENTAGE BY WHICH ACTUAL KWH SALES EXCEEDED FORECAST SALES
1980	12,550	13,577	8.18%
1981	12,494	13,577	8.67%
1982	12,693	13,577	6.96%
1983	13,270	13,577	2.31%

The CHAIRMAN. I understand that. A brief summary you'd had in skimming testimony of yesterday—a difference between a 2-percent growth rate and a 4-percent growth rate is not 2 percent; it's 100 percent.

And that's the reason I asked the question.

Mr. BOGGS. I see. No, it's definitely percent on the base. It's not a——

The CHAIRMAN. Percent on the total base.

Mr. BOGGS. Yes.

The CHAIRMAN. And you also note that New York State Public Service Commission reports that LILCO will have insufficient generation to meet its peak load.

Are there other alternatives available, other than voltage reduction?

Mr. BOGGS. Certainly when you speak about a single company's service area, we have fairly strong connections between utilities, particularly in the Northeastern and Midwestern part of the country. So that is not, in and of itself, an indication that service will become unreliable, because I'm sure that LILCO is generally a consistent purchaser of power from outside its own generation.

The CHAIRMAN. And maybe it's cheaper for them to buy expensive power in the short run than it is to buy expensive capacity they must finance over the longer term.

Mr. BOGGS. That obviously varies, both with the accounting system and with the reality of the individual situation.

The other aspect that has to be mentioned in consideration of that kind of decision is the difference between sunk costs and variable costs. In effect, even the most expensive nuclear plant, once operating, is almost invariably cheaper than the alternative running costs. I have seen the figures from Diablo Canyon, that now in operation it is saving on the order of tens of millions of dollars a month that would not have been saved, had it not operated, given that it was already constructed and the money was already spent.

The CHAIRMAN. Senator Ford.

Senator FORD. Mr. Boggs, on page 4 of your statement you say that demand for electricity will rise. I haven't had an opportunity to read all of it, but what is the percentage, and over what period of time do you think electricity demand will rise?

Mr. BOGGS. Well, it's much more difficult to summarize that than to make the one-line statement. You're quite correct.

My personal opinion, which is I think fairly close in fact to what our energy information administration and others are projecting, is that electricity demand will come to close to GNP growth but lag somewhat behind it, and that given any kind of reasonable economic growth for this country—which I think we all seek—you would be looking at something between about 2 and 3 percent.

Senator FORD. Isn't that a little bit higher than the testimony we got yesterday?

Mr. BOGGS. I don't think so. Of course, you got a fairly wide variety, but to the extent that I looked at it, I think somewhere in the 2's—if you had to make each guy give you one number, I think as I looked at it, they were mostly 2.3, 2.4, 2.7, those kinds of numbers.

Senator FORD. So whatever they said, you took the low and high point and said it's somewhere between them.

Mr. BOGGS. No. I assure you that in fact it was quite independent. I mean I give you, for whatever it is worth—and economic forecasters do not have a very good track record—my independent derivation. As I say, others have large computer models and they seem to come someplace in the same range.

Senator FORD. The second point you made on it, that lights will not go out in this decade, that's the next 5 years—will we have any brownouts? That's not necessarily the lights going out, but getting dim as hell.

Mr. BOGGS. Well, clearly, you'd have to distinguish between their operational difficulties, which is every year there's some blackouts and some brownouts. If you look at it as anything systematic or anything out of the ordinary of what we see across the country, it would be my estimation that the answer is basically no.

Regional situations do differ somewhat, although the interconnections of regions, as we discussed in the LILCO situtio, mitigate that. But personally, I would certainly be surprised to see within this decade any kind of a significant problem that we have not seen in the past.

Senator FORD. You made another point there; that we need an appropriate amount of new construction at the appropriate time.

As I listen to you and those we listened to yesterday, it's all a guess, because we're going to find testimony today that says that the increase will be over 3 percent—3.2 in fact is one.

I find the utilities in the position that the best estimate from their major customers and historical projection, and then the movement to construct and the economy drops, the utility is in a catch-22. If they have the capacity and no one wants it, everybody's mad at them. If people need capacity and they do not have it, everyone's mad at them. So there's really no way.

The aluminum industry in the Northwest and other areas were talking about how aluminum has dropped in price, in the last year maybe from 80 cents to 40 cents, and their ability to pay for power is diluted considerably.

I find quite a disconcerting situation for the utility industry as a whole. I asked those several gentlemen that were here yesterday if they would build a major generating facility of 1200 megawatts or more today, unless directed by a regulatory agency. And their answer was a unanimous no, they would not build one.

Would you agree with them that, according to your judgment, this is not the appropriate time for new construction?

Mr. BOGGS. First, I would agree that their statement is probably correct as to their views. And second, I would say that it would be my personal judgment that it is probably not the time this year; that is, that if all constraints were removed, if the regulatory system were either as good as they would like or as free as someone would like, I personally don't think the people would be beginning construction of major new plants, whether of 1200 megawatts or of 600 megawatts—right now.

Now, 2 years from now, 4 years from now, that could be different.

Senator FORD. Did you scan through the testimony of those people, rather than the statements—or in addition to the statements yesterday?

Mr. BOGGS. I have not seen any of the transcripts, just what's been in the public press.

Senator FORD. Well, the major reason they gave—and I hope I'm right, Mr. Chairman—is that it's the real interest rates that would prevent them from doing it; that we hear a lot—and I said well, we hear—they said interest rates bothered them. And I said, well, we hear about interest rates dropping from 21 percent down to 12 percent or 13 percent, whatever it might be—or less. They said, that has nothing to do with it. It's the real interest rate. And they underscored "real" interest rate, and that was an impediment to them doing any kind of construction.

Would you agree that if you were in their position, you would take the same position, that the real interest rates—not interest rates as such—but the real interest rate would be an impediment?

Mr. BOGGS. Well, Senator, there's certainly a vast amount of construction that has been begun in this country in the last two or three years under the same sets of interest rates. I can't say that I have otherwise studied through that extensively.

I would note that although the real interest rate is an interesting construct, I think for them the important thing is their ability to recover costs in the charges that they can make. You see, the real interest rate is driven by the overall consumer price index. But for the electric company, the important thing from a monetary point of view is what they will be able to collect in their rates.

And that seems to me that the major driver comes back to what you said earlier; their ability to collect under either the regulatory system or some other system a return that will make them able to pay off the debt that they incur.

Senator **Ford**. Well, last week the long 20-year bonds for utilities, I believe, was at around a 11.55 percent interest rate. And inflation is under 4 percent. The historical difference between inflation and interest has been four points. This would make it somewhere in the neighborhood of eight points. So it is double the historical difference.

The real interest rates are very, very high. And I think that's indicated.

We also have the problem of politics. And politics is the public service commissions or however you want it. Some of them are appointive; some of them are elected; and their main plank on their platform is holding utility rates down. The only people that they can squeeze is the utility themselves, and I agree with holding the rates down, but we're not taking our foot off in any way the pressures on utilities. I don't want to give them free reign.

We hear a lot about free market in the last several years. Everything ought to be out there and do the best you can with what's available, but we still find—that's a regulated industry and not deregulated—so we find that one of the major complaints when you take a poll are utility rates. They're all included, whether it's electricity or gas or whatever it might be.

I find it a very, very untenable position that we've placed the utilities in. I'm not fighting their battle today, but I think that there is a degree of fairness somewhere, and we've got to find that fair ground.

I'm not sure I'm correct in this, but there is a commission—FASB—that looks at the accounting system. You're talking about the accounting system. And is there a proposed change in the accounting system for utilities?

Mr. **Boggs**. No, Senator——

Senator **Ford**. You dwelled on that pretty hard and talked about the accounting system.

Mr. **Boggs**. The subjects the FASB and those sorts of things are more in the technical method of accounting as opposed to the concept that electric rates are based on a particular rate base, a rate of return, and that's the underlying system by which utilities have been regulated over the decades. So it's not a question of some commission being able to come in and tinker with something. It's a fundamental way in which we have done things, and it worked quite well as long as every new plant that came in was cheaper than the one before, as long as we had the paradigm of a public utility, a permanently declining cost curve.

That's why you hear people say that a new plant costs 20 cents a kilowatt hour, let's say, the first year, even though over time it may only cost 5 cents. Now, that leads to quite different decisions about whether something makes sense, about how your rates should be structured.

So it's not a tinkering that a commission, that a technical commission could change. It's something that public utilities commissions have to confront, and in some ways they have. The idea that there's something wrong with the system, I think, has become more pervasive. Some believe in greater use of construction work in progress is the answer. Others believe that greater phase-in of rates, so that they don't go up as sharply, but perhaps they remain higher longer.

I don't think there is any one answer, but I think people are starting to identify that as a problem, so-called rate shock when plants come in, because of this conventional method of accounting.

Senator FORD. How do utilities shoulder the problem when they have a mix of industrial customers and residential customers and the economy sags to a point where the industrial customers do not need as much electricity, and there may not be a so-called take and pay contract, and they begin to cut back, and the expense of that entity is still there? That monthly payment or annual payment is still there.

And, of course, the only place they have would be the residential area, and yet I suspect that commissions in the various States would be very reluctant to give any kind of an increase as it relates to residential customers.

Is there—what kind of procedure—that's just the business world, and that's tough, I guess you'd say. They made a bad judgment. The economy is not necessarily in the hands of the local government or local industry. That economy is based on what happens in this town, in my opinion, and so if the economy is not helped, and we do not make the right kind of decisions, the decisions of others are somewhat skewed based on what they project and the best available information.

Do you see any way, or do you have a hard-hearted approach to it?

Mr. BOGGS. Senator, normally public utility commissions, every couple of years, through so-called rate cases, try to thrash out these issues. Currently in most areas, in very rough terms, industrial, commercial, and residential each have a somewhat similar share. And in any 1 or 2 years, while the effect that you indicate does take place, there are usually only moderate shifts. So 2 years later you come in, people make projections, the commission comes to some decision about what your rate structure will be.

Yes, you're correct that over time, the residential share has been growing and commissions have had some reluctance to increase the rates that residences have borne. This is an issue that is fought out in every State in the rate case, and I think you'll have some witnesses this afternoon from the industrial side who will probably have some extensive testimony on that—and maybe others of the contrary view.

Basically, there is a procedure to try to work it out. I think you're exactly right as to the direction that politics affects it. But probably over time, some adjustment is made. I mean we have seen, in fact, residential rates, rise quite substantially in the past decade; not as fast as industrial rates, but they, too, have had to bear their share of the increased costs.

Senator FORD. I find that all charges interrelate. People are mad because telephone rates are going up, the access charge. We get hundreds of letters about that. And that becomes a rate, and they talk about rates, and they paint with a broad brush—paint with a broad brush.

Some of the commercial banks with loans to private utilities have been giving them a year or two leniency where they just pay the interest rates, are forgiven the principal. It seems like that—it seems to be working out, based on what the projection might be that they will get around to it. That's one heck of a way to run a railroad when you have to have your payments delayed. That seems to be a way of life now, where we have so many bankruptcies, particularly in our State, your State and mine.

I read the business section of the Courier Journal every Monday morning for bankruptcies filed the week before, major farm bankruptcies. Next is real estate, next is air-conditioning, plumbing and heating. It all relates in those major bankruptcies.

We've got lots of problems out there and I just hope the plug stays in for a while.

Thank you, Mr. Chairman.

The CHAIRMAN. Thank you.

Senator Evans?

Senator EVANS. Thank you, Mr. Chairman.

I find your testimony going in two different directions. I guess I'd like to first probe a little bit more on your report on LILCO and their problems. Some of it is in quotes and some of it isn't, and so I don't know quite what comes from the commission and what's derived from your own interpolations.

On page 3, the middle, you say, the Public Service Commission reports that "LILCO will have insufficient generation to meet its peak load." I don't know at what point they're projecting that. Do you know? Now? Ten years from now? Five years from now?

Mr. BOGGS. I believe that that is today. This was basically the question that Senator McClure asked; that looking at it on a single company basis, that was the fact. As I indicated, there are interconnections where some companies are at times net buyers and others are net sellers, but the quotation is with regard to the current time.

Senator EVANS. Did the Commission in its report go on beyond that quotation to say anything about its ability to purchase power and handle that problem of insufficent generation of its own to peak loads?

Mr. BOGGS. I don't have the quotation at hand. My impression is that they did indicate that power—purchased power was available. It's a question of how much and at what price.

We could provide the full opinion or the relevant portions if you would like.

[The information follows:]

The New York Public Service Commission, in its May 16 report on power availability for the summer of 1985 in New York State, finds that LILCO's problem is immediate and is exacerbated by transmission limitations. The report notes on page 3 that the New York Power Pool and Con Ed, which are not as geographically isolated as LILCO, do not face such transmission limitations.

The Public Service Commission report finds that LILCO will not have sufficient generation to meet its requirement for meeting peak load (page 2, especially last three lines, and Table I). It also finds that LILCO's transmission limitations will probably make voltage reductions necessary at the time of peak demand in the summer of 1985:

> "LILCO has transmission capacity sufficient to import energy to cover its load, but not to meet the generating reserve requirements. Under our projections, it will be necessary for LILCO to take operating relief measures to meet its needs, such as emergency imports using consolidated Edison transmission and voltage reductions. Under adverse circumstances, it is possible because of the limited transmission capability that load shedding might be necessary." [pp. 3-4, underlining added by DOE for emphasis]

The report also states (pg. 9):

> "LILCO has experienced operating reserve deficiencies during periods of high load each of the last two summers. We expect conditions in 1985 to be significantly worse."

LILCO's problem is also made worse by the fact that demand is growing more rapidly in its service territory than elsewhere in New York. To quote the report (pp. 9-10):

> "Load growth in the LILCO Territory has been higher than anticipated. For example, Draft STATE ENERGY MASTER PLAN III projected a 1985 peak at 3121 MW. The current projection of the company is 3300 or almost 180 MW higher. In addition, LILCO in the past has depended on a transmission line tie to New England for about 140 MW. New England's capacity problems make it extremely unlikely that any capacity will be available over this tie."

I would also note that on August 15, LILCO faced an all-time peak demand of 3365 MW, higher than the peak of 3300 MW projected in the report. The complete text of the report is attached.

STATE OF NEW YORK
Public Service Commission
Paul L. Gioia, Chairman

Three Empire State Plaza, Albany, NY 12223
Further Details: (518) 474-7080

85070/PR

FOR RELEASE: IMMEDIATE

GIOIA ISSUES STAFF REPORT ON SUMMER POWER OUTLOOK FOR STATE, CON EDISON AND LILCO

Albany, May 16 -- Paul L. Gioia, Chairman of the Public Service Commission, issued today the Department of Public Service Staff's annual report and forecast of the electric supply situation for the summer for the New York Power Pool (NYPP), Consolidated Edison and the Long Island Lighting Company (LILCO). Separate studies are done for Consolidated Edison and LILCO because, unlike the other utilities, they are subject to transmission constraints with respect to the delivery of additional power.

The Power Pool has projected a statewide peak load of 22,420 MW for 1985, an increase of 2% over the record load of 21,971 MW which occurred last June 11. It also projects peak loads for Con Edison of 7,625 (up 1.5% over 1984) and for LILCO of 3,300 MW (up 6.5% over the actual 1984 peak and 2.6% over the peak which would have occurred in 984 had a voltage reduction not been implemented).

Staff has forecasted that the NYPP and Consolidated Edison will have sufficient generation to meet their projected peak loads, but will not have sufficient surplus to meet their operating reserve requirements. However, NYPP and Consolidated Edison have sufficient transmission ties to neighboring pools and systems to enable them to purchase the additional power necessary to meet their operating reserve requirements, assuming spare capacity is available.

Staff's analysis reveals a more difficult situation with respect to LILCO. Under the projections used by staff, LILCO will have insufficient generation to meet its forecasted peak load. The company has the transmission capacity to import enough power to meet its peak load -- but with virtually no reserve margin. Under the projections used in staff's analysis, therefore, it will be necessary for LILCO to utilize "relief measures" in order to meet its operating reserve requirements during times of peak load. These relief measures would include voltage reductions and the emergency import of power from Consolidated Edison. The emergency imports from Con Edison are dependent upon the availability of at least some of the Astoria units. These relief measures should be adequate to provide LILCO with sufficient power to meet its peak load and operating reserve requirements, under staff's assumptions. If LILCO experiences more adverse conditions, stronger relief measures, including load shedding, may be necessary.

LILCO has experienced operating reserve deficiencies during periods of high load each of the last two summers, but staff expects conditions in 1985 to be significantly worse. One reason for this is that load growth in the LILCO territory has been higher than anticipated. In addition, LILCO in the past has depended on a transmission line tie to New England for about 140 MW. New England's capacity problems make it extremely unlikely that any capacity will be available over this tie. Rather, staff expects that the NYPP will be called upon during the summer to help New England.

Another significant difference from last year is the increase of import capacity on a tie between New York and Hydro Quebec from 1,300 to 1,800 MW. In order to protect against the potential loss of this larger Canadian tie, the operating reserve requirements of all of the utilities has been increased by a total of 750 MW.

Staff has utilized average historical operating data to project operating conditions for summer 1985. Its outage forecast is based on average historical data and the NYPP and the member systems' projected load is based on average weather conditions assuming some additional amount for growth. If conditions at the time of the peak load are not close to average, then staff's projection will not be accurate.

Chairman Gioia has directed the Power Pool and LILCO to submit reports on their plans to minimize any risk of service problems during the summer peak period, and has directed staff to closely monitor the situation.

A copy of the staff report is attached.

NEW YORK POWER POOL
1985 SUMMER OPERATING RESERVE
PROJECTION AND ANALYSIS

Prepared By

Staff of the
Department of Public Service

May 1985

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INTRODUCTION

This report provides an analysis of the New York Power Pool's (NYPP) projected 1985 summer operating reserve margins (available generation capacity above peak load) of the statewide system, Consolidated Edison Company of New York (Consolidated Edison), and Long Island Lighting Company (LILCO).

Staff considered the adequacy of the reserve margins on both an installed and operating basis. Consolidated Edison and LILCO have been studied independently due to their susceptibility to transmission contingencies.

Staff projected unavailable capacity figures statistically. Estimated peak loads, scheduled outages, installed capacity, and transfer limit information for the 1985 summer period were provided by the NYPP, Consolidated Edison, and LILCO.

Staff's findings and conclusions are based on a current estimate of operating conditions for the 1985 summer. If subsequent system events adversely affect the integrity of the bulk power supply system, a reassessment of system reliability will be necessary.

SUMMARY

The NYPP has projected that its peak load will reach 22,420 MW for the 1985 summer. This is 2 percent higher than the all time highest peak load of 21,971 MW which occurred on June 11, 1984. Consolidated Edison and LILCO peak loads are expected to be 7,625 MW and 3,300 MW respectively. Both utilities anticipate their peak loads to be higher than the 1984 peak -- Consolidated Edison by 1.5 percent and LILCO by 6.5 percent.[1]

The NYPP requires each member system to maintain an 18 percent installed generating reserve above its peak load. If each member system maintains this 18 percent requirement, then the NYPP will have a 22 percent installed reserve margin. For summer 1985 the required installed capacity for NYPP, Consolidated Edison, and LILCO is 27,352 MW, 8,998 MW, and 3,894 MW, respectively (TABLE I). While the NYPP and Consolidated Edison have adequate installed reserves, LILCO, with 3,767 MW of installed capacity, will be short some 127 MW in meeting its requirement.

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[1] LILCO's 1984 peak load of 3,096 MW would have been higher by approximately 120 MW or 3.9 percent were it not for a system wide voltage reduction on June 11. The LILCO peak is therefore projected as 2.6 percent over the calculated peak for 1984.

The NYPP also requires that each utility maintain generating capacity on line or quickly available (e.g., gas turbines) to meet its load plus an "operating reserve" to assist in meeting unplanned outages. This reserve is necessary so the power system can withstand emergencies with a greater measure of reliability.

Staff has forecasted that operating reserves at peak load times will be less than required for NYPP, Consolidated Edison, and LILCO. NYPP's anticipated operating reserve margin of 1,617 MW (TABLE VI) is short some 1,083 MW of meeting its 2,700 MW reserve requirement.[1] Similarly Consolidated Edison's projected operating reserve of 401 MW falls 512 MW short of its 913 MW reserve requirement (TABLE V). LILCO is projected to be 507 MW short of meeting its required reserve set at 391 MW (TABLE IV). Thus, it will have to buy capacity to meet both its load and operating reserve.

The NYPP and Consolidated Edison have strong tie lines to neighboring pools and systems that will enable delivery of energy in the event of a major loss of generation, assuming spare capacity is available. LILCO has transmission capacity sufficient to import energy to cover its load, but not to meet the operating reserve requirement. Under our projections, it will be necessary for LILCO to take operating relief measures to meet its needs, such as emergency imports using Consolidated Edison transmission and voltage reduction. Under adverse circumstances, it is possible because of the limited transmission capability that load shedding may be necessary.

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[1] Modifications to the interconnection with Hydro Quebec will allow importation of an additional 500 MW this summer. As noted below, this additional import capability will result in the need to provide a significantly higher pool operating reserve.

I. GENERATING CAPACITY

A. Installed Capacity

TABLE I shows that, based on this summer's projected peak loads, the NYPP, Consolidated Edison, and LILCO will have installed reserve requirements of 27,352 MW, 8,998 MW, and 3,894 MW, respectively. While Consolidated Edison and NYPP will meet this requirement, LILCO, for the first time in many years, will not. The 127 MW installed reserve shortage will have to be purchased from the NYPP. As we will discuss later, average levels of generator outages at LILCO are projected to exhaust its reserve, creating a high probability that LILCO will not be able to meet its peak load and operating reserve without relief measures.

B. Scheduled Outage

Indian Point 3 (965 MW capacity), owned by NYPA, is scheduled to be out of service this summer for refueling and maintenance. No other major generating unit has been scheduled out of service this summer in the downstate area. There are units scheduled for overhaul in the upstate area and the New York Power Pool is closely examining the possible rescheduling of certain work.

Several sizeable units are or will be undergoing spring maintenance with planned early June return-to-service dates. Units in this category include Roseton 2 (600 MW), Astoria 3 (353 MW), Bowline 2 (600 MW), and Port Jefferson 2 (370 MW) for a total of 1,923 MW.

Some of these units could experience delayed return-to-service dates thereby reducing the operating reserve margin further during the beginning of the summer period. Last year the NYPP (and many of its member systems individually) experienced its record summer peak load of 21,971 MW on June 11, 1984. The early peak electric demand occurred during the scheduled outage of a large amount of capacity. The NYPP had to purchase energy from Canada to meet its operating needs while Pennsylvania-New Jersey-Maryland (PJM) had to go into a voltage reduction. If high loads occur, therefore, in the late spring, scheduled outages and extended spring outages can cause operating reserve shortages.

C. Total Unavailable Capacity

Total unavailable capacity is that amount of generation unavailable to meet load. This includes planned or scheduled outages, forced outages, deratings, and capacity out for economic reasons (reserve shutdown). TABLE II, included at the end of this report, presents the average amount of unavailable capacity for the summers of 1982, 1983, and 1984, as well as a forecast for the summer of 1985. The forecast is based on the unplanned average outage level of the three prior summers plus the specific planned outages for this summer. Staff projects that LILCO will have 583 MW of generation out of service during the summer; Consolidated Edison, 1,847 MW (does not include Indian Point No. 3 or Polletti of PASNY); and NYPP, 7,839 MW.

II. TRANSMISSION CAPACITY

A. Consolidated Edison Company of New York

Consolidated Edison's normal transmission import capability for summer 1985 is expected to be 4,003 MW (TABLE II). Normal transmission limits are set so that the loss of one facility will not overload any of the others. Under storm watch operating conditions, and the greater likelihood of transmission outages, transmission limits are set so that the loss of two facilities will not overload any of those remaining in service.

For summer 1985 the storm watch transmission import capability will be 2,663 MW. The import limits for both normal operation and storm watch conditions are some 600 MW lower than last summer. Changes in generation and transmission circulation patterns for this summer have caused the reduced import level.[1]

Subtracting total committed capacity of 2,653 MW[2] from the normal and storm watch transfer limits results in emergency transfer capability of 1,350 MW and 10 MW, respectively. These amounts can be used for economy purchases from upstate to reduce expensive Consolidated

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[1] Includes increased imports from Hydro Quebec over the 765 kV tie line, the operation of Somerset (not in service last summer) and altered power flows in New Jersey. The maximum flow on the 765 kV is increasing from 1,300 MW to 1,800 MW due to improvements on the Canadian side.

[2] Committed to firm purchases and energy from Consolidated Edison's generation located north of its service territory.

Edison oil-fired generation. It should be pointed out that utilization of transmission import capability to import energy for any reason is subject to the availability of external generation.

B. Long Island Lighting Company

LILCO's normal transmission import capability is expected to be 260 MW. This is LILCO's share of the normal capacity of it major tie to Consolidated Edison. LILCO has a 138 kV tie line with Connecticut from Northport with a normal limit of 140 MW. However, the New England pool has indicated that it expects severe operating problems in peak periods, and it is unlikely that it will be able to deliver any power to LILCO during peak load periods.

The normal rating of the tie lines to Consolidated Edison is 560 MW. However, because Consolidated Edison co-owns the major tie line with LILCO, by agreement, Consolidated Edison utilizes 300 MW of that capacity to wheel power to Brooklyn and Queens. During emergencies, if Consolidated Edison's generation is available at Astoria, Consolidated Edison could drop the wheeling of electricity to its territory and therefore deliver an extra 300 MW to LILCO. Under emergency conditions it is also likely that an additional 13 MW could be imported to LILCO over other smaller ties with Consolidated Edison. Therefore TABLE IV shows an emergency transmission import capability of an additional 313 MW to LILCO. This scenario assumes that at least some Astoria units are operating. There is likely to be an economic penalty to Consolidated Edison in running Astoria units above their economic level.

III. LOAD AND OPERATING RESERVE FORECAST

A. Consolidated Edison Company of New York

TABLE V summarizes a staff estimate of 1985 summer electric load, generating capacity, and operating reserve for Consolidated Edison. Total installed capacity plus firm purchases and NYPA generation will equal 12,141 MW. This will meet the forecast peak load of 8,775 MW with a 3,366 MW gross generating reserve margin. Projected unavailable capacity of 2,965 (which assumes Indian Point 3 out of service for maintenance) at the time of the peak results in a net generating reserve margin (operating reserve) of 401 MW. This level is not adequate to meet Consolidated Edison's operating reserve requirement of 913 MW.

To meet its reserve requirement at the time of its peak load Consolidated Edison will have to purchase reserve and depend on its transmission import capacity for its delivery in the event of an unexpected loss of generation. TABLE V shows that Consolidated Edison's transmission import capability of 1,350 MW (from TABLE III) will handle the operating reserve deficiency with a 838 MW surplus.

B. Long Island Lighting Company

TABLE IV summarizes a staff estimate of the 1985 summer electric load, capacity, and reserves for the LILCO system. LILCO has experienced operating reserve deficiencies during periods of high load each of the last two summers. We expect conditions in 1985 to be significantly worse. Load growth in the LILCO territory has been higher than anticipated. For example, Draft STATE ENERGY MASTER

PLAN III projected a 1985 peak at 3121 MW. The current projection of the company (reviewed for reasonableness by our economic research staff) is 3300 or almost 180 MW higher. In addition, LILCO in the past has depended on a transmission line tie to New England for about 140 MW. New England's capacity problems make it extremely unlikely that any capacity will be available over this tie. Rather, we expect that the NYPP will be called upon during the summer to help New England.

Our projection shows that LILCO's generation will not meet its operating reserve requirements at the time of its peak load. In fact, assuming average levels of unavailable capacity -- 583 MW -- LILCO may not even be able to meet its forecast load, i.e., LILCO will have to import energy over its tie lines. The normal transmission import capability of 260 MW should be sufficient to import enough capacity for LILCO to meet its peak load, but the company will have virtually no operating reserve for emergencies. Under these circumstances, relief measures will likely become necessary.

We have provided on TABLE IV a listing of possible operating relief measures that can be taken to meet capacity shortages. Combining these measures, LILCO should be able to avoid actual load shedding during high load periods because the total relief provided, 485 MW, is greater than the projected operating reserve deficit. This assumes however,that voltage reduction is implemented and, more importantly, that generation is available at Astoria on the Con Ed system to allow the emergency import of 313 MW from Consolidated Edison on the Con Ed tie.

During high load periods LILCO may be buying virtually its entire reserve from the NYPP. Under our projections, LILCO would be required to implement relief measures if unavailable capacity is "normal". In the event that LILCO loses a major generating unit (in addition to the units covered by the average or normal unavailable capacity figures), LILCO's tie lines would become overloaded. To prevent these lines from tripping out of service and compounding the problem, load shedding would be required immediately. Our forecast, which indicates load and capacity almost in balance with no reserve, suggests that load shedding could occur, although it is not likely.

From an operating perspective we conclude that LILCO's capacity shortage problem will cause an increased potential for the need to use operating relief measures including voltage reduction.

C. New York Power Pool

TABLE VI summarizes staff's estimate of the 1985 summer electric load, capacity, and reserves for the entire NYPP system. The NYPP expects to have 30,948 MW of installed capacity and, in addition, plans to purchase 928 MW of firm capacity. The total of 31,876 MW is 9,456 MW greater than the anticipated summer peak load of 22,420. This gross generating reserve margin of 9,456 MW will be adequate to sustain staff forecasted outage levels of 7,839 MW. However, the resulting net operating reserve of 1,617 MW will not be sufficient to meet the NYPP's own operating reserve standard of 2,700 MW. An important change this year that impacts the shortfall is the increase of import capacity on the 765 kV tie to Hydro Quebec from 1,300 to 1,800 MW. Under the pool's procedures, sufficient capacity should be available equal to 1-1/2 times the largest likely system contingency. The operating reserve requirement is 750 MW higher than last year to protect against the potential loss of the Canadian tie.

IV. WORST CASE ANALYSIS

Staff has utilized average historical operating data to project operating conditions for summer 1985. Our outage forecast is based on average historical data and the NYPP and the member systems' projected load is based on average weather conditions assuming some additional amount for growth. If conditions at the time of the peak load are not close to average, then our projection will not be accurate.

Taking into consideration the fact that record peak loads have occurred outside the principal hot months of the summer each of the last two years (September 6, 1983, and June 11, 1984), it is possible that a major hot spell during the mid-summer months would result in loads significantly higher than projected. If a significantly higher load were to occur at the same time that generator outages were above average, major operating problems could result.

Except for LILCO, staff's projection excludes the use of operating relief measures, such as voltage reduction and load shedding. Under worst case conditions (significantly higher load than projected and higher than average generator outages) operating relief measures, including voltage reduction become likely throughout the pool and load shedding may be required in southeast New York.

TABLE I

INSTALLED RESERVE REQUIREMENTS [1]

	LILCO	Consolidated Edison	NYPP
Installed Capacity	3,714	9,451	30,948
Firm Purchase	53	900	928
TOTAL CAPACITY	3,767	10,351	31,876
Forecast Peak Load	3,300	7,625	22,420
Required Capacity[2]	3,894	8,998	27,352
Surplus or (Deficiency)	(127)	1,353	4,524

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[1] From data supplied by LILCO, Consolidated Edison, and NYPP.

[2] NYPP requires each member system to maintain 18 percent installed generating reserves above its system peak load. Required installed capacity is 1.18 times the peak load. This is projected to result in NYPP installed capacity of 1.22 times its peak load.

TABLE II

TOTAL UNAVAILABLE CAPACITY AND PLANNED OUTAGES[1]

- Mid-June thru Mid-September -

Year	Total Unavailable Capacity (MW)	Planned Outages (MW)	Unplanned Outages (1-2) (MW)	Total Capacity (MW)	% of Capacity Unavailable (1 divide 4)	% of Capacity Planned (2 divide 4)	% of Capacity Unplanned (3 divide 4)
LONG ISLAND LIGHTING COMPANY							
1982	656	153	503	3,721	17.6	4.1	13.5
1983	636	239	397	3,721	17.1	6.4	10.7
1984	547	262	285	3,721	14.7	7.0	7.7
1985[2]	583	212	371	3,714	15.7	5.7	10.0
CONSOLIDATED EDISON COMPANY OF NEW YORK							
1982	2,222	99	2,123	9,368	23.7	1.1	22.7
1983	1,118	65	1,053	9,330	12.0	0.7	11.3
1984	2,851	833	2,018	9,423	30.3	8.8	21.4
1985[2]	1,847	121	1,726	9,451	19.5	1.3	18.3
NEW YORK POWER POOL							
1982	8,077	1,080	6,997	30,102	26.8	3.6	23.2
1983	7,232	1,651	5,581	30,236	23.9	5.5	18.5
1984	6,972	1,754	5,218	30,305	23.0	5.8	17.2
1985[2]	7,839	2,205	5,634	30,948	25.3	7.1	18.2

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[1] From data supplied to the department by LILCO, Consolidated Edison, and NYPP except as noted.

[2] Staff projection using average levels of unplanned outages over the last three summres and adding planned outages for this summer.

TABLE III

TRANSFER LIMITS UPSTATE NEW YORK TO CONSOLIDATED EDISON[1] [2]

	Normal Operating Conditions (MW)	Storm Watch Operating Conditions (MW)[3]
Absolute Limit	4,003	2,663
Less Committed Capacity:		
Consolidated Edison Northern Capacity		
Bowline	800	800
Roseton	480	480
Fitzpatrick	160	160
Hydro Quebec	740	740
LILCO Obligation	300	300
NYSEG Obligation	146	146
Long Island Municipals	27	27
TOTAL COMMITTED	2,653	2,653
Surplus Available for Emergency Transfer	1,350	10

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[1] From data supplied by Consolidated Edison. Assumes Indian Point 3 is out of service.

[2] Includes power through the Public Service Electric and Gas System (New Jersey) and into New York City.

[3] Under storm watch conditions transfer limits are established so that the simultaneous loss of two transmission facilities does not cause the remaining lines to exceed emergency limits. Normal limits are established based on the loss of a single transmission line.

TABLE IV

LILCO: OPERATING RESERVE SUMMARY

CAPACITY	1985 (MW)
LILCO Installed	3,714
FitzPatrick	53
TOTAL CAPACITY	3,767
LOAD	
Peak Load	3,300
TOTAL LOAD	
Capacity minus load (Gross Reserve)	467
Less Forecast Unavailable[1]	583
Operating Reserve	(116)
Operating Reserve Requirement[2]	391
Surplus or (Deficiency)	(507)
Transmission Import Capability	260
Less dedicated Imports	53
Less NYPA customers[3]	64
Surplus or (Deficiency)	(364)
Relief Measures: Municipal Generation	52
Emergency Transmission Import	313
Voltage Reduction	120
	485

[1] Staff projection using average levels of unplanned outages over the last summers and adding planned outages for this summer.

[2] Reserve requirement represents LILCO's share of NYPP operating reserve requirement based on 1,800 MW single contingency in 1985 and a 2,400 MW single contingency thereafter. The largest single contingency is the tie to Hydro Quebec, 765 kV, which will be able to carry 1,800 MW in 1985 and 2,400 MW beginning in 1986.

[3] Municipals: 27; Brookhaven: 27; Grumman: 10.

TABLE V

Consolidated Edison: Operating Reserve Summary Summer 1985[1]

	Forecast (MW)
CAPACITY:	
Consolidated Edison	9,451
Polletti	825
Indian Point 3	965
Firm Purchases:	
Hydro Quebec	740
Fitzpatrick	160
TOTAL CAPACITY	12,141
PEAK LOAD:	
Consolidated Edison customers	7,625
NYPA customers	1,150
TOTAL LOAD	8,775
Capacity minus load (Gross Reserve)	3,366
Less Forecast Unavailable Capacity	2,965[2]
Operating Reserve	401
Operating Reserve Requirement	913[3]
Surplus (Deficiency)	(512)
Transmission Import Capability	1,350
Surplus	838

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[1] From data supplied by Consolidated Edison except as noted.

[2] Staff projection using average levels of unplanned outages over the last three summers for Consolidated Edison service territory generation (includes NYPA generation) and adding planned outages for this summer.

[3] The NYPP sets the statewide operating reserve requirement by multiplying the single largest contingency by 1.5. For 1985 summer the largest contingency will be the 765 kV tie to Hydro Quebec loaded at maximum of 1,800 MW. (1,800 X 1.5 = 2,700 MW.) Consolidated Edison's portion of this is 913 MW.

TABLE VI

NYPP: Operating Reserve Summary Summer 1985[1/]

	Forecast (MW)
CAPACITY:	
Installed	30,948
Firm Purchases	928
TOTAL CAPACITY:	31,876
LOAD:	
NYPP	22,420
Capacity minus Load (Gross Reserve)	9,456
Less Forecast Unavailable Capacity	7,839[2/]
Operating Reserve	1,617
Operating Reserve Requirement	2,700
Surplus or (Deficiency)	(1,083)

[1/] From data supplied by the NYPP except as noted.

[2/] From TABLE II.

The CHAIRMAN. Would the Senator yield on that point, because I wanted to follow up on that as well.

Does that relate to the other quotation that just precedes that in your testimony, and that is the New England Power Pool projection that record electric demand this summer, coupled with the likelihood of scanned emergency power sales from New York State, could lead to a regional power shortage.

Mr. BOGGS. Does it relate in the sense that——

The CHAIRMAN. LILCO's ability to buy off-system.

Mr. BOGGS. If everyone is in the situation of taking in one another's washing, ultimately you can't do it. I think that, obviously, there are several levels of analysis; the single company level; then there's smaller regions; and then there are larger regions

But taken all together, the New England/New York area is one that on almost all of the analysis, is shown as being one of the areas that would come first toward some type of problem if either existing construction doesn't come into play as planned or if additional construction is not undertaken in the future.

Senator EVANS. It seems to me it would have been a more complete statement to have included the other explanation. Someone reading this statement would assume that there is no other way they can meet their peak loads if they have insufficient generation.

Now, I suppose I could say the same thing about Snohomish County PUD in the State of Washington that serves almost half a million people. They certainly have insufficient generation to meet their loads because they have no generation at all. They buy all their power from Bonneville.

I think that—and I'd like to continue into the next sentence, where it says LILCO will probably have to resort to unusual steps, including voltage reduction. Is that your own interpolation? That's not in quotes, and I presume that that doesn't come from the report of the Public Service Commission.

Mr. BOGGS. Senator, I can get you that answer. I don't have the answer on that part of the prepared testimony.

[The information follows:]

THE NEW YORK PUBLIC SERVICE COMMISSION REPORT STATES (pp 3-4):

Under our projections, it will be necessary for LILCO to take operating relief measures to meet its needs, such as emergency imports using Consolidated Edison transmission *and voltage reduction*. Under adverse circumstances, it is possible because of the limited transmission capability that load shedding may be necessary." (Italic added by DOE for emphasis.)

Senator EVANS. Where would you place voltage reductions in the list of things you would do to make loads and demand match?

Mr. BOGGS. Well, in the short term it's essentially first. I mean that happens. In fact, we have voltage reductions on utilities on a fairly regular basis, regular in the sense that it will happen several times a year on a number of utilities.

I would have to get you the specific examples, but I'm sure that there have been a number of cases already this year on high, hot summer days, where there have been voltage reductions on significant numbers of systems.

[The information follows:]

One example of voltage reduction in order to maintain reliability of service is that of LILCO itself, which on June 11, 1984 had to reduce voltage because of inadequate generation and transmission capability combined with high demand. Specifically, LILCO first reduced voltage by 5%; then, after one of its largest units unexpectedly went out of service, LILCO had to reduce voltage by another 3% to 8%.

The North American Electric Reliability Council (NERC) maintains for its own use records of "disturbances and unusual occurrences" in electrical systems. According to these records, from 1980 through 1984 roughly 30 such incidents were reported annually, most of which were due to equipment malfunction or acts of nature such as lightning strikes. Eighteen incidents in these 5 years (3.6 events annually), however, were voltage reductions and/or public appeals apparently caused by a combination of high demand and inadequate capacity available for use. In 1985, through early July, there were 26 reports of "disturbances and unusual occurrences," of which 7 were voltage reductions and/or public appeals, all occurring on January 21, an extremely cold day, over much of the eastern United States.

Senator EVANS. Then why do you call it an unusual step?

Mr. BOGGS. Well, it's unusual to the people who have to undergo it, and ideally you wouldn't have any, and some utilities in some places haven't. It's unusual in the sense that it's not part of normal operation.

Senator EVANS. One—I found it rather strange that in your entire testimony, all 15 or 16 pages, there was not one mention of alternative ways to manage our electric power system, not one mention of efficiency, not one mention of purchased conservation, not one mention of seeking out alternative ways to meet the demands which will be there regardless of the growth rates you mentioned.

You know, your 1.7 to 4.4, I think, translates into a doubling of power demand in one case in 40 years, in the other case in 16 years, which is quite a difference, but it is an increase in demand. It's just a question of time. And the real question, then, is what you do about it.

Why not seek out the least cost way of providing that energy, rather than just concentrating on new, large central station construction?

Mr. BOGGS. Well, Senator, I don't think you find anything in the testimony either referring explicitly to large central station generation. I tried to indicate the overall situation that we see coming. Some of those alternatives are embedded in projections. I think if you look at Mr. Sant's testimony—I forget whether that was Tuesday or today he has some good discussion of, in effect, the amount of conservation that is already embedded in estimates. I certainly do not want to be read—and I don't think the statement, fairly read, implies that one particular outcome is better than another, that inherently or intrinsically, coal is going to be cheaper than nuclear or nuclear is going to be cheaper than solar, or wind is going to be better than either.

But I think that—in fact, I thought that was the burden of the conclusion of my oral statement—that we need to have these options open and that we would do better to try to figure out a way to assess them fairly and not have each one trying to knock down the other.

Senator EVANS. I think that that's certainly a respectable direction to take. The written testimony gave me a totally different picture—perhaps a misreading—but when I found nothing of one kind in there and an extensive discussion of the difficulties of new investment based on the regulators and their decisions on prudency, it seems to me that——

Mr. BOGGS. Senator, let me interpolate a moment, that regulatory decisions and constraints on investment may easily constrain all types of alternatives as well. Many, if not most, of the alternative generating technologies are at least as capital-intensive as a conventional central station on a per kilowatt basis. And certainly in dicussions on the tax bill, you hear that from those industries.

A good bit of the discussion of these past decisions of utility commissions was dedicated to show, I think, why in effect the past ways of doing things seemed to be breaking down. It wasn't necessarily directed toward a particular solution. That is, electricity in one sense has been a marvelous component of America's growth, and from 1910 to 1970 or so, it seemed to be going along without huge policy problems.

And one of the questions that you have to ask or that you really have to explain to the public as well is, why things have changed. And that's why part of the testimony was directed in that direction.

Senator EVANS. It seems to me things have changed. You know, it was a cinch to be a utility executive or a public regulator for all of those years, because new capacity was—the marginal cost was lower than the average cost of electricity. It was easy to have a surplus, and it was even easier to sell it as prices came down. And regulators met about once every 5 years or 10 years sometimes, to even talk about changing the utility rates.

Mr. BOGGS. And they mostly met for the purpose of reducing.

Senator EVANS. That's right.

Mr. BOGGS. Real electricity prices, I think, fell so that in 1971, real prices were about one-fifth of their level a few decades earlier. And in fact, even with the increases that we've had, real electricity prices today are lower than they were in the 1950's or anytime earlier.

Senator EVANS. In fact, in the Northwest, in spite of our 700 percent increases in rates, even the nominal rates are about half what they were in 1920 and 1925. But doesn't that indicate that we have really turned a corner? Some day we may even find ourselves back in a position where, putting all of these very expensive central plants into the rate base, we'll find better and more efficient new ways of creating electricity and once again the marginal cost may be lower than the embedded cost, and we'll be back on a diffent curve.

But at least for the foreseeable future, we're in a totally different situation than we once were. Doesn't that really make it important to view things a little differently? It seems to me we can't afford to blithely say we need 25 percent excess capacity. You know, that's the prudency rule of many years ago. We've got to find ways to fuel a little closer to the line, still retain reliability, but do it by acting a little smarter than we did. We have to.

Mr. BOGGS. Well, those are certainly all alternatives. I think that one of the things that I would hope would come out of a hearing like this is that there is a wide array of alternatives and that they have to be looked at, I think, on a very careful and individual basis.

I've been intrigued by the use of the phrase "least cost." I think Mr. Sant has tried to trademark it. I'm not sure if he's been successful or not. And my reading of it is that that is a very intelligent concept, but it's a question, not an answer. That is, looking at things in a least cost fashion does not in fact tell you whether the best answer is $20 light bulbs or $2 billion nuclear plants, or load management, or pumped storage hydro.

These are all potential answers and they have to be looked at on an individual basis. That's why I tried to focus on the question of what kind of a system, do we have to try to make those decisions? Do we have a system or can we have a system that will match risks and rewards, that will match costs and benefits?

Senator EVANS. I agree with you. That's a question, not an answer, but it's a question that hasn't even been asked with any regularity up until very recently. And I think it's a terribly important question now to ask, and it will broaden our expectations of what we do.

How do you view pricing as a way of load management? Do you think currently, with marginal costs of electricity being considerably higher than the average, would you advocate a pricing system, would you suggest that regulators try to reflect that cost somehow in rates so that people get the appropriate pricing of what new electricity costs?

Mr. BOGGS. Of course, that's a very difficult question.

Senator EVANS. I know it is.

Mr. BOGGS. That's the reason you asked it.

Senator EVANS. The answer is even more difficult, I think.

Mr. BOGGS. For one thing, curves that look very neat on paper don't necessarily reflect all realities. When we talk about marginal cost, even though that looks future-oriented, it's really looking to last year's marginal cost. It's not necessarily looking to next year's. It may be, as you indicated, that we're at a hump; that some of the marginal cost that's coming into service may be the highest that we will see for a long time. Again, it might not.

You also have in the electric utility industry the very significant distinction between the transmission, distribution, and generation of electricity. The transmission and distribution—especially the distribution—looks a lot more like a conventional monopoly in the terms of public utility theory; the transmission, sometimes a little less so; the generation may be even less so.

I don't think I am prepared at this time to take a general swipe at saying that you ought to have a different methodology in saying everybody goes to marginal cost. Because for one thing, determining marginal costs is much more difficult than determining average costs.

Senator EVANS. Let me ask in a different way, do you believe that it is appropriate to continue just marching ahead and giving signals based on the average cost of electrical generation for a utility and to the customers? I recognize that there may be great difficulty, but let's just talk about it on the basis of the concept. Average cost, or some price signal that—isn't that what the market is supposed to do, is give appropriate price signals to customers?

Mr. BOGGS. And that depends a lot on what the rest of the system is doing, what your range of possible costs and benefits are.

Simply raising the price or lowering the price by the regulators will not necessarily give you a better outcome. I think you need to look at it much more thoroughly and fundamentally, and I guess I'm not able to think it through and come to a single answer in this kind of a forum.

Senator **Evans**. What about the—currently and I think traditionally, utilities generally operated with a 20–25 percent excess capacity or excess margin. Do you think that's appropriate, given the current circumstances, at least the current view of marginal costs of new plants, particularly central generating plants?

Mr. **Boggs**. That's a good question. Let me say a couple of things. First, when we use percentages, like 15 or 20 percent margin, you have to be careful about what you're using in the numerator, what you're using in the denominator.

In all of my testimony, I've used what I understand to be the conventional method, which is that you take the peak and add to it the percentage of the peak which is not used and get up to what's called the "capability," which is a lower than nameplate "capacity."

Now, we have a historical series on that in the sense that we have it back at least into the forties, and the lowest we ever had for any year on our summer peak was about 15 or 16 percent. I know there are a lot of studies, and I'm not an expert, but I would take them that if you get below certainly 15, your chances of having significant outages become great.

Now, that too should be a subject for close analysis. I know in the technical literature, there is a lot of it. It obviously is affected by how much of your load is weather-sensitive. It's affected by how many plants, how interconnected you are, and a whole range of things. So I agree that it's a subject for careful analysis.

In order to run with a lower margin, a lower numerical margin, and still have reliable service, you have to do other things that have costs. For example, you can buy outages from industries. In your area of the country, you can get the aluminum plants to agree to shut down.

Now, to get them to shut down on 24 hours' notice may be a lot easier than to get them to shut down on 15 minutes' notice, and you have to look at those costs across the board. Again, I would agree with you that it's worth looking at. I don't think that the situation is such that it's automatically correct that that is cheaper than new generation.

That also relates, however, to who is bearing those risk and rewards. If the utility has to make that decision to invest its own $2 billion, you might get a different answer than if an entrepreneurial company could build that plant and sell its output over the next 30 or 40 years.

That ties into who's locked in what. Under that kind of system, a consumer wouldn't be locked into the cost of the plant if it turned out to be too high. On the other hand, he'd have to pay the price if it turned out that it was the best alternative.

All I'm saying is that I don't think you can automatically say that a given alternative is going to be cheaper than another one. You have to look at it carefully and you have to look at it individually. There may be some areas of the country where you have big loads that can be shed immediately, and that's a good idea. And I understand there are places where that's being done. In fact, we have some Department of Energy physics facilities that we can shed a couple of hundred megawatts on short order, and we get a lower rate for it.

In other areas, your load may not be of that type.

Senator EVANS. Well, I agree. It seems to me that that's what we need to be headed for, is a broader view of this whole thing, taking into account various ways of getting at the answer we need, which is efficient electricity. Capacity is really the problem in most of the country. It doesn't happen to be a big problem in our part of the country. It is energy rather than capacity which constrains in the Northwest.

But it seems to me that it's terribly important now for every utility to take a look at those costs and the risk of time, which seems to me the biggest risk of all, the time it takes between decision and the flow of electricity on a major new central plant. And we ought to be doing what we can, it seems to me in Congress, to help shed that length of time or help minimize that length of time through whatever regulatory changes we can make.

Mr. BOGGS. I agree with you completely, Senator.

Senator EVANS. Doesn't it make sense for these utilities then, to really pretty actively take a look at such things as load shedding. Our friendly PEPCO here in Washington, DC sent me—and I guess all of its customers—an offer to hook up to an electronic load cutoff with an offer for lower rates. Now, it happens, as I looked at it, the offer wasn't good enough. But obviously they're not offering anymore than they think they have to, and I'm not buying because it isn't good enough.

But I suspect that they've got a big distance to go. I don't know it, but I'll just bet that they've got a big distance to go in offering that load shedding before they get to the point where it's cheaper to go out and build a new central station to add additional capacity.

And I just hope that utilities get aggressive enough and smart enough to realize that, and that customers are smart enough not to sell out too cheap.

Mr. BOGGS. I agree with you, Senator, that that's a promising technique. I would only note that, as your own example shows, the uncertainty as to what the consumer response is going to be could easily be significant in that area as well, so that if you're trying——

Senator EVANS. I don't think there's an uncertainty at all. All they have to do is test the market. Offer a certain price, see how many do it; raise the price if they have to. I think it's very much the same thing as when the airlines overbook and they come aboard the airplane and say, OK, who wants to get off? We'll offer 75 bucks, and $100, and they get an offer up high enough, and there will be people who——

Mr. BOGGS. There's no uncertainty that they can do it ultimately. There's clearly uncertainty, though, as to whether it's economical, because if they have to raise it high enough to get you to agree, then it may be different than if they have to raise it high enough to get another percentage to agree. And if you're looking 10 years out, to try to plan and say, well, we're sure that we can shed 100 megawatts 10 years out, I would just caution that there is some uncertainty in that, too, as to what the costs would be.

Senator EVANS. Doesn't that offer, however, the potential at those times when, for whatever reason, we've gotten into a real jam—people talk about combustion turbines. We've got to have combustion turbines because we can build them fast and that's what the utility executives said. That was the answer if we really run into an emergency.

But even if the price is high, isn't load shedding a way—voluntary load shedding, that is—at a price, a way to get pretty quick action, even though it may be expensive—solar combustion turbine?

Mr. BOGGS. Well, I guess I'm a believer that at a high enough price you can get almost anything. But the question is, at a reasonable price, how voluntary is it going to be, ultimately? And some of the things Senator Ford said about the reaction of the public in the case of having their service significantly degraded I think is something that can't be looked at totally blithely.

Senator EVANS. Thank you.

The CHAIRMAN. Senator Hecht?

Senator HECHT. Thank you, Mr. Chairman. No questions.

The CHAIRMAN. Mr. Boggs, let me follow through just a moment, because I certainly agree with what Senator Evans is saying, and with what you are saying. And I understand you to share at least the opinion that indeed these alternatives need to be studied and analyzed and evaluated and in some instances tested and tried.

But let's look at voluntary load shedding as an example. Who gets out of the deal, and when, and upon which decision? Maybe you get a load shedding offer and the customer signs up for that load shedding, and when he doesn't get interrupted very much, very often, he's happy with the deal.

Suddenly as things get a little tighter and he's finding more outages, more interruptions of his service and less tolerance for that degree of interruption, he decides, hey, I don't like this deal anymore. I'm going to get out of it.

Should we bind the utility to the load shedding agreement? Should we bind the consumer to the load shedding agreement? And, if so, over what periods of time? Should we require a customer who signs a load shedding agreement to agree to abide by that over a rolling 10-year period—so that he's bound, even if he finds that it begins to pinch a little—and if we don't bind him, then what happens to the load forecast system?

Mr. BOGGS. Senator, I think you've stated admirably in the form of questions the uncertainty that I was relating to the former questioner; that what is voluntary when you sign up for it may seem much less voluntary if you sign a long-term contract and it starts to pinch you. The certainty of how something will work 10 years from now may only be there if in fact you have those long-term contracts. You have to renew them every several years.

And that was my point; that your projection of what your voluntary sign-up is going to be 10 years out could be very uncertain.

The CHAIRMAN. I remember when we went through the natural gas shortages and you were also in this town. I remember some of the conversations that took place at that time as we looked at a number of emergency users, people who demanded service because it was an emergency if they didn't get it—cities, fire departments, hospitals, many of whom had signed interruptible contracts because the rate was lower. But then when they got interrupted they came in and said, hey wait, not me, because I have an essential community service that must be provided.

How do we deal with the question of the person who signs the contract for interruptible service, and then later comes in and says, but you can't possibly mean me.

Mr. Boggs. Well, that's a good question. I think the reality that's out there right now, to the extent that that's being used, is that nobody is going—at least on the residential side—nobody is going for interruptibilty on their total use, in the way we got into in natural gas. On manufacturing, industrial facilities, there's a greater possibility of that.

I think we probably will not go so far as to trigger the totality of the problem that you indicate, but at the same time that's a reason that we will probably not go so far as to get the kind of response that the most optimistic would look for.

The Chairman. Should we say to schools and hospitals and police departments and fire stations that they cannot sign interruptible contracts?

Mr. Boggs. Well, as you say, who is the "we"? The State commissions generally monitor and regulate these activities. I would think the political pressures against them doing that would be pretty great.

The Chairman. Well, it strikes me the that when we run into shortages, people cascade on us and say, but I am entitled to priority. I am critical to society. I provide something that society must have. And they have no compulsion, and we find very little hesitancy in responding to that demand by saying, yes, indeed you are. In the event of an emergency, you have a priority.

Maybe those that are entitled to priority in the event of an emergency are those who should not be permitted to sign interruptible contracts.

Mr. Boggs. Well, that's a tough decision—if it weighs the intelligence and autonomy of those making the decision against the political firmness of the political decisionmakers in times of crisis.

The Chairman. I really wish you'd said that more slowly so people could focus on it. [Laughter.]

Mr. Boggs. I'm not sure I can repeat it.

The Chairman. Do you really believe that there is any political firmness in time of crisis? You've been around this town through two energy crises. Did you see political firmness here?

Mr. Boggs. Well, that's why I said it had to be weighed off. [Laughter.]

The Chairman. OK. That's why I wanted you to say it more slowly.

How far should we go in providing a risk-free environment for utilities?

Mr. Boggs. I would say not too far. That's a broad answer to a broad question.

Obviously, the less the risk to some extent, the less the incentive for some of the economies and efficiencies that make the rest of the society go. I guess I try to use the phrase that there has to be some matching of risks and rewards.

The CHAIRMAN. In other words, the greater the risk, the greater the reward; the lower the risk, the lower the reward. Is that what you're saying?

Mr. BOGGS. And even more explicitly, the greater the potential for risk, the greater the potential for reward—because you don't know how it will come out in any given situation.

The CHAIRMAN. Are you suggesting that if we're going to saddle utilities with mismangement or imprudence decisions, that we ought to free up market rates on the other side?

Mr. BOGGS. I'm saying that that's something that needs to be considered if you're looking at the question of will new investment be made.

The CHAIRMAN. The opportunity costs for energy are far higher than the embedded costs in today's market. Isn't that correct? Particularly in utilities?

Mr. BOGGS. For many utilities. Although I don't have the figures at my fingertips, we certainly face the prospect of some of that reversing because as companies come over their humps of construction in the very unusual environment of the 1970's, they are now getting very high embedded costs that are being worked off.

But certainly in many cases, that is true.

The CHAIRMAN. Utility regulatory theory in application in the past at least has said, look at the historic costs; what did you invest? Depreciate that investment; you're entitled to a return on that investment plus your cost of operation, plus reasonable profit on that operation.

That was, in general, utility pricing policy.

Mr. BOGGS. That's correct.

The CHAIRMAN. And as costs rise over time, if you go through an inflationary period, generally construction costs rise or replacement costs are higher than the original costs. But the baseloaded system, one that has high capital cost embedded in the past, can and is required to provide service at less than the cost of the current costs of capital and investment.

If we go to market pricing, almost anything else, you have market tests that say, well, how much will people pay for it? General Motors doesn't really price their automobiles on the basis of how much they invested in the plant over a period of time. That's certainly a factor. But they also test the market. If the price is too high, people don't buy; they either have to reduce the output of that model or lower the price in order to move it, if they can, and stay in business.

Should utilities be permitted to test the market in the same way and see what the market will bear?

Mr. BOGGS. Well, let me emphasize that there are two possible ways to do what you talked about. One is talking about the purchase of new generation by a utility, and the other is the whole system of pricing of utilities to customers.

And in my testimony, I was focusing more on the question of the new generating plants. I think those are separable issues, and I've focused on the generating side because I think that's more likely to be seen by a wide array of interests as plausible as we go out into the future.

I would note also that as we change or seem to have changed from an inflationary period to a deflationary one, we shouldn't always look at the past for exactly what's going to happen. That is, the embedded cost of capital, the average return on equity being allowed, is coming a lot closer to what the current costs are, and conceivably could cross at some point in the future. Then you'd have people coming in and looking at it the other way. So we have to be a little cautious about thinking that today's conditions will persist forever.

The CHAIRMAN. Can you tell me what the difference is between mismanagement and imprudence?

Mr. BOGGS. No.

The CHAIRMAN. Are not public utility commissions attempting to make that differentiation?

Mr. BOGGS. Well, of course, each commission has its own laws, regulations, and case law to guide it. Certainly there are many cases where decisions were made that 99 percent of the people in the same situation at the same time would have taken the same decision, that have later been held to be imprudent.

At the same time, I am sure there have been a lot of cases where people have not done things as well or as smartly as they could. I'm not a public utility lawyer, so I can't tell you where the bright line of prudence or mismanagement is supposed to be. I'm sure none of us does things 100 percent right, and few of us do them 100 percent wrong. But somewhere between there, on current law, commissions try to draw a line or they have the power to draw a line; because I must say that I think that a fair amount of what's happening today has been tied to what the rest of the circumstances are.

That is, if you got a bunch of MBA's to look at prudency, I'm sure there were decisions made in the 1950's and 1960's that weren't very smart either. But they came in an era when prices were generally stable or falling, and people were not inclined to be picky about it.

Today, in an era when, because of other factors, prices may be rising sharply, there's clearly a political incentive to be much more searching in examining decisions.

The CHAIRMAN. Let me make just one comment in that regard. It seems to me that if we're going to apply 20/20 hindsight—no, let me rephrase that.

If we're going to hold utilities to the standard that says that if you made a misjudgment in the past you must bear the cost of that misjudgment, then we're also going to have to loosen up on their opportunity to reap the benefits of good judgments in the past.

You said that a little differently in your statement. But that would indicate that the commissions, if they're going to penalize for what they determine to be imprudence, not just mismanagement—which I would differentiate—if they're going to penalize imprudence, then they're also going to have to allow recovery at higher than normal utility recovery rates for the good judgments. Is that not correct?

Mr. BOGGS. Basically, I'd say two things about that. One, you've put it in a context of what's right and equitable, and I think that's correct. On top of that, I think we need to notice that whatever you think about the fairness or equity of that, people are simply not going to make those investments under the current kinds of rules.

And that goes even one step beyond.

The CHAIRMAN. And you will also begin to see reflected the kind of statements that were made to us yesterday; that under the current climate, I simply would not, as a utility manager, undertake construction of any additions to our system because there is the risk of penalty for imprudence and no opportunity for reward for good judgment.

Mr. BOGGS. That is certainly true. I would say that at least as I read it in the public press, not having read that transcript, that the questions or the answers were couched in terms of the situation today; that they might well not want to build today, even if the regulatory system were ideal.

The CHAIRMAN. I think that there is some element of that, certainly. You don't really make those judgments today if you can cut it a little closer to the time when you'll need it. And maybe you'll hit it right, and maybe the only penalty will be that there will be shortages, and shortages are not penalized, but imprudence is.

Mr. BOGGS. Well, shortages of course—I'm sure that, as well, the companies understand that realistically there are political penalties that are paid, even if not instantaneous economic ones. We've seen that with the gas pipelines. And I thought Senator Evans' remark with regard to the fact that things that we can do to reduce those lead times, things like the administration's or other nuclear licensing reform bills, some other legislation in these areas—give us all a better opportunity to both reduce costs and avoid shortages.

The CHAIRMAN. You outlined a number of problems in your oral statement and your prepared statement, some of which seem to be embedded in regulatory processes. They are regulatory problems.

What's the solution that you would suggest?

Mr. BOGGS. Well, there are obviously a whole range of things. I think that one of the things that we need to know or to notice is that there is not a single panacea. It's not all turning to wind, or it's not reforming the NRC or anything in between.

I think that continuing to emphasize that there has to be this correlation of risks and rewards is important. I think getting across the idea that we need to maintain options is important. With those ideas in mind, there are then in every State and in the Federal Government and in the different administrative agencies, whole series of steps.

I mentioned the licensing reform. I think experiments or consideration of freeing up markets—I mentioned the FERC is doing some of this. I notice the Illinois Commerce Commission testimony, I thought was eloquent on some of these areas; that, to the extent that we can get these ideas moving across a whole range of areas, hearings such as this, your leadership in putting this problem on the table, is probably not going to be reflected in the one single Electric Utility Salvation Act of 1986 or the Electric Consumer Salvation Act, but, rather, in a whole series of intelligent moves made in a whole series of places.

The CHAIRMAN. Is it not correct that the decisions that are made in a given utility service area—assume it's wholly within one State—the decisions by that public utility and then the decisions by the regulatory commission within that State will have or may have consequences that flow across the boundaries of that State?

Mr. BOGGS. They certainly may have, I think particularly in terms of putting that utility in the situation either of excess capacity or of excess demand, which then frequently puts them on the interstate market either as a buyer or a seller.

The CHAIRMAN. And if their costs run up and they have excess capacity and somebody else has excess demand, then the purchaser in another place may pay a higher rate because of their higher cost?

Mr. BOGGS. Well, it sometimes works the other ways, because the buyer is not compelled to buy. It's that very high cost of the excess capacity that puts the seller on the market in a distress sale situation.

The CHAIRMAN. The market effects may be felt in States other than where the decision was made.

Mr. BOGGS. That's certainly true.

The CHAIRMAN. Does that justify Federal intervention?

Mr. BOGGS. Well, there's clearly some degree of Federal intervention already. I think that I would not say that it justifies generic Federal control of the system because the effect of those kinds of decisions occurs across the board. One State doesn't permit an auto plant to be sited in its State; that clearly affects the economy elsewhere, and there is no real end to that principle.

At the same time, the FERC's control, especially over the rates of interstate transactions, means that there is an opportunity for Federal policy to affect what happens. If those rates are set too low, in effect it can reward the grasshoppers who had insufficient capacity, or underforecasted. That's a sort of a whole other question as to how changes might be made in that, but I think it's worth recognizing that it's not just a case of additional Federal intervention: that there is a certain Federal hand already in those FERC controls.

And Chairman O'Connor and the Commission, in their notices of inquiry which are now pending, I think have at least offered the opportunity for some intelligent comment on that. The Department of Energy will be filing comments on those notices of inquiry, and until we do I don't really have a final answer on what they will be, but we're certainly looking at them with interest.

The CHAIRMAN. Your final comment perhaps answered my last question, and that is, you don't see any need for legislation—at this time, you do not see any need for legislation that changes the State/Federal relationship in this field.

Mr. BOGGS. There's no legislation that we are at this time supporting. It may be in the discussions on the FERC testimony, that something might come out of it, but there is no position at this time for any new legislation.

The **Chairman**. Mr. Secretary, thank you very much for your testimony this morning and for providing us with some insights into some of the problems that we're trying to deal with.

Thank you again.

We'll next hear from a panel—Dr. Helmut Merklein, the Administrator of the Energy Information Administration; Dr. David Bodde from the Congressional Budget Office; and Dr. Richard Rowberg from the Office of Technology Assessment.

Gentlemen, in each instance, your prepared statement will be made a part of the record in full. I would invite you to summarize the statement, hit the high points, and then we'll proceed to the questioning.

Dr. Merklein.

STATEMENT OF HON. HELMUT A. MERKLEIN, ADMINISTRATOR, ENERGY INFORMATION ADMINISTRATION, DEPARTMENT OF ENERGY; ACCOMPANIED BY ROBERT T. EYNON, CHIEF, DATA ANALYSIS AND FORECASTING BRANCH, ELECTRIC POWER DIVISION; AND MARY J. HUTZLER, DIRECTOR, ELECTRIC POWER DIVISION

Dr. **Merklein**. Mr. Chairman, members of the committee, I am pleased to be here today to present the data analyses prepared by the Energy Information Administration, EIA, on the current capabilities and future prospects of the electric generating industry in the United States.

With me today are Mary Hutzler. She is the director of EIA's Electric Power Division, who is hiding behind the panel and we'll get her attention in a minute; and Mr. Rob Eynon on my left, who is chief of the Data Analysis and Forecasting Branch.

That's the lady—in the white dress—Mary Hutzler, who is having her birthday today.

The **Chairman**. Are we supposed to stop and sing "Happy Birthday", or can we just note it for the record? We do wish you a happy birthday.

Dr. **Merklein**. Let me refer to table 1 in the written testimony for the next few numbers that I will quote to you. In the 1984 Annual Energy Outlook published in January 1985, we projected an annual average growth rate of 3.2 percent for electricity demand between 1985 and 1995 in our mid-case scenario. This projection is based on economic growth averaging about 2.7 percent per year.

I would like now to have Mary uncover the chart that I will discuss in some more detail. Our analysis is limited to 10 years, ending in 1995—that is, the formal analysis. If demand growth continues after 1995, additional capacity, of course, will be needed beyond that indicated in this table, and I will go into that in a minute.

Alternate assumptions about economic growth result in a range of growth rates for electricity sales, between 2.7 and 3.8 percent. And that is not in the table. Those forecasts are contained in my written statement. The growth rates are comparable to forecasts prepared by the Department of Energy; in its National Energy Policy Plan—they use 2.6 percent—and within the range of forecasts, by and large, prepared by the utility industry. We might be just a little high relative to them.

From the end of 1984, EIA is projecting generating capacity to increase at a rate of 1.6 percent per year. And in view of the projected demand increase, this implies that the current cushion in underutilized generating capacity will diminish over time, given our projections, as I said, of expected demand growth.

And now to the chart. We expect requirements for generating capacity to be 792 gigawatts in 1995 as shown on the chart, and that is the mid-case scenario. This capacity is expected to include 663 gigawatts capacity that is in operation today, and it assumes no retirements and no deterioration in performance of existing plants—and I'll deal with that question later.

Furthermore, we project 119 gigawatts of planned additions based on current construction activities and by announcements concerning construction by utilities. These planned additions include 82 gigawatts that are either currently under construction or in operation or testing and 37 gigawatts of announced plants.

Given our assumption that all planned additions will be completed and that all of the plants will be retained in service—that is, refurbished—our 1995 shortfall capacity is projected to be 10 gigawatts in the mid-GNP growth case. That shortfall is expected to go up by 2000.

We estimate that about 49 gigawatts of nuclear generating capacity are scheduled to begin operation between 1985 and 1995. These plants account for 38 percent of the total capacity additions projected to come on line during this period. Nuclear power represents a significant portion of projected electricity generation in 1995, something like 19 percent.

About 8 percent of all power supplied in 1995 is projected to be from nuclear plants coming into service over the next 10 years.

There are many factors that govern the outcome of our projections, of course, particularly those that affect individual regions of the country. The primary sources of fuels used to generate electricity, demand growth patterns, and transmission capabilities differ regionally and have varying impacts, and this has been dealt with in the first day of hearings.

For example, imports from Canada have become a significant component of electricity supply in the northeastern United States. Although imports of electricity currently provide less than 2 percent of total U.S. requirements, it is likely that these imports will increase over the next few years.

Electricity imported in the northeastern United States has grown from about 6 percent of that region's generation in 1980 to 13 percent in 1984. Recent forecasts estimate that in 1990, imported power from Canada could be as much as 20 percent of total generation in the northeastern United States, assuming that power is not needed to meet requirements in Canada.

Now, as we look across the various areas of the United States, we see that some regions could experience difficulties in meeting demand reliably. In the EIA mid-case scenario, the western United States is projected to require capacity additions that are not currently under construction.

Other areas—New England, mid-Atlantic, Southwest and Central—are projected to use up more of their capacity cushions than the Nation as a whole, and they may experience difficulties after the 1995 period beyond our detailed projections.

In summary, I would like to restate a number of points. Electricity generating capacity is adequate to meet our current needs. There are at least three reasons, however, why we may need to be concerned about the future:

1. The advancing age of generating plants could leave us without adequate capacity;
2. The potential for demand growth could be greater than expected; and
3. Our continued dependence on capacity that burns expensive oil and natural gas could leave us vulnerable to future shortages of these fuels, especially oil.

EIA projections show that the growth rate for electricity demand is expected to be higher than the rate of new capacity additions, indicating that the capacity cushion that exists today will be reduced in the future. If demand growth continues after 1995, substantial additional capacity will be needed. Proper planning by utilities will have to take place to ensure that needed facilities will be available.

Individual areas of the country could experience problems in meeting projected demand if expected nuclear and coal capacity additions are not completed as scheduled, if demand grows more rapidly than expected, or if capacity additions are not started in time to meet demand. Under these conditions, oil and gas consumption would be greater than projected and consumers could face higher costs for electricity.

Now, as with any forecasting endeavor, there are many reasons why the forecast, including ours, may not be realized. Assumptions about growth in the economy, world oil prices, adherence to current laws and regulations, as well as many other factors combine to form a unique set of conditions that strongly influence particular outcomes.

Though we at EIA try to produce forecasts that capture all factors and determine national level results, we have not represented conditions at the regional level in sufficient detail to have the same level of confidence.

That concludes my summary of the written statement.

[The prepared statement of Dr. Merklein follows:]

TESTIMONY OF

DR. HELMUT A. MERKLEIN

ADMINISTRATOR, ENERGY INFORMATION ADMINISTRATION

BEFORE THE

COMMITTEE ON ENERGY AND NATURAL RESOURCES

UNITED STATES SENATE

JULY 25, 1985

ON

ELECTRICITY SHORTAGES IN THE 1990's

Mr. Chairman and Members of the Committee, I am pleased to appear before you to present data and analysis prepared by the Energy Information Administration (EIA) on the current capabilities and future prospects of the electric generating industry in the United States. With me today are Mary Hutzler, Director of EIA's Electric Power Division, and Robert Eynon, Chief of the Data Analysis and Forecasting Branch. As you are aware, EIA collects a great deal of information from the electric utility industry in order to assess both the current status and likely future for electric power. These data lead us to a number of conclusions about the industry.

The electric generating capability of this country is vital to the well-being of our society and critical to our continued economic development. The electric utility industry is special, too, because of the large commitments of capital that are needed to facilitate its expansion and the long leadtimes needed to bring economically efficient new capacity on line.

This country enjoys a level of electric service that is unparalleled elsewhere. Electric service is not only available in all corners of the land but is able, with an extraordinary degree of reliability, to meet the needs of users. In the United States today, we have 672 gigawatts of nameplate capacity available to meet current needs for electricity. Analysts are in general agreement that this capacity is more than adequate to meet the Nation's current needs. However, problems could occur that result from unique conditions within a local area.

As we probe further, however, we discover that there may be areas for concern about the future. Of the installed fossil-fuel steam capacity used to meet baseload needs, almost 22 percent of this resource is 25 years old or older and will need to be refurbished or replaced in the next 10 to 15 years because of physical deterioration or economic obsolescence. Also, 164 gigawatts of this capacity are fueled with either oil or natural gas--fuels that are expensive now and may become more expensive in the future. We note also that a number of factors, including aging of plants, installation of environmental control systems, and the reduction in the growth rate of demand in recent years have contributed to the overall lower performance of our power plants. Between 1970 and 1984, the average power plant capacity factor (a measure of how much electricity is actually produced divided by the electricity produced if the plant operated continuously) decreased from 51 percent to 41 percent. The declines are probably due to a slowdown in the growth rate for electricity and, to a lesser extent, to pollution abatement restrictions and deterioration in the generating system.

Regional diversity in generating sources is reflected in the variation in electricity prices paid by residential customers, used to generate electricity. For example, a residential customer served by the municipal utility City of Seattle currently pays about $10.00 for 500 kilowatthours of electricity. By contrast, a residential customer served by Consolidated Edison in New York City pays about $78.00 for 500 kilowatthours of electricity. Although these are not typical customers, the rates for comparable usage levels are cited for comparison. Many factors are responsible for this wide range in prices, including taxes, labor costs, and local conditions that affect distribution costs. However, variations in fuel costs are also important determinants of electricity prices. In this example, electricity produced by the City of Seattle comes from cheap Federally subsidized hydroelectric sources while a substantial portion of the power produced by Consolidated Edison comes from relatively expensive oil. Hydroelectric plants provide the cheapest source of electricity generation, in part because the fuel is water which is renewable and in part because many of these plants have been subsidized. Oil-fired generating plants are the most expensive source.

With these factors in mind, let us turn to the future and consider both the growth patterns of electricity usage and the stock of generating capacity. In the 1984 Annual Energy Outlook published in January 1985, the Energy Information Administration projected an annual average growth rate of 3.2 percent for electricity demand between 1985 and 1995 in its midcase scenario as shown in Table 1. This projection is based on growth in the economy averaging about 2.7 percent per year between 1985 and 1995. It is important to note that our analysis is limited to the next 10 years, ending in 1995. If demand growth continues after 1995, additional capacity will be needed beyond that indicated here. Alternate assumptions about economic growth result in a range of electricity sales growth rates from 2.7 to 3.8 percent per year. These growth rates are comparable to forecasts prepared by the Department of Energy in its National Energy Policy Plan and within the range of forecasts prepared by the utility industry. From the end of 1984, EIA is projecting generating capacity to grow at a rate of 1.6 percent per year. This implies that whatever "cushion" exists today in underutilized generating capacity (over demand requirements) will begin to disappear as we move into the future. Figure 1 shows significant increases in capacity additions in the early and middle 1970's. As we move from the mid-1970's to the future, we can see a decline in capacity additions. This means that the cushion of capacity that came into service in the 1970's will diminish over time given our projections of new capacity additions and expected demand growth.

We expect requirements for generating capacity to range between 785 and 806 gigawatts in 1995 as shown in Table 2. This capacity is expected to include 663 gigawatts of capacity (nameplate rating) that is in operation today and assumes no retirements. Utilities have reported to EIA that retirements could be as much as 19 gigawatts by 1995, most of which would be uneconomic oil and gas steam capacity. Some industry analysts indicate that additional capacity will be retired by the year 2000. In addition we project 119 gigawatts of planned additions based on current construction activities and announcements by utilities. These planned additions include 82 gigawatts that are either currently under construction or in operational testing. The remaining 37 gigawatts of announced plants include almost 32 gigawatts of coal generation for which no construction has taken place. The planned capacity includes 60 gigawatts of coal capacity, 49 gigawatts of nuclear capacity, and 10 gigawatts of other capacity including hydroelectric plants and turbines. Of course, additional capacity could be added.

We project the need for additional plants that are neither under construction nor announced. In 1995, this "shortfall" capacity ranges from 3 to 24 gigawatts depending on the level of economic growth assumed (2.0 to 3.4 percent per year from 1985 to 1995). This additional capacity includes both steam plants that require long leadtimes for permits and construction (about 6 to 8 years for a coal-fired plant) as well as turbines that have much shorter construction periods (less than 2 years). For example, in EIA's high economic growth case where electricity demand is projected to grow at the rate of 3.8 percent per year, about

5 gigawatts of the 24 gigawatts in unplanned plants are coal steam, while the remainder are new turbines. In the low economic case, the 3 gigawatts are almost all coal steam plants. In the past, utilities have planned for needed new capacity without Federal intervention and, given the proper incentives, it seems reasonable that utilities will plan for future power needs.

In the longer run, the planned new capacity will be used to meet new demand and is not expected to reduce generation from existing oil- and gas-fired plants. Between 1978 and 1984, electric utilities reduced the share of electric generation from oil and natural gas from 30 to 17 percent. Over the forecast horizon we expect this share to vary from 14 to 19 percent over the cases analyzed. Because capacity additions are not expected to keep pace with the growth in electricity demand, EIA projects that the quantities of oil and natural gas used by utilities in existing steam plants will increase in the future. Regions dependent on oil and natural gas are projected to build capacity to meet demand growth but not sufficient to displace existing oil- and gas-fired steam generation.

The operation of new, efficient coal-fired and nuclear plants, coupled with the slowdown in building programs by electric utilities, is expected to result in slight decreases in real electricity prices nationally. We project that real electricity prices will on average decline (0.3 percent per year) between now and 1995. By comparison, we project that real oil and natural gas prices in the end-use sectors will increase, especially after 1990. Individual utilities with commitments to large construction programs are likely to incur price increases, which are expected to diminish over time as new plants are depreciated. Electricity prices are composed of both variable and fixed components. Variable costs include fuel, operations, and maintenance costs and are expected to increase over time. Fixed costs are associated with recovery of investment in plant and equipment. EIA projects that the fixed portion of electricity prices will diminish in the future because planned expenditures by utilities for new plants are lower than historical levels (reflecting less new plant construction) and because decreases will occur in depreciation costs for existing plants. The decrease in the share of fixed costs offsets a substantial portion of the expected increase in variable costs, so that the total real cost of electricity is projected to be relatively stable over the next 10 years. Obviously, this pattern of electricity prices cannot be sustained indefinitely. Eventually, investments will have to be made to provide the capacity needed for future demand growth and to replace existing plants.

There is a high degree of uncertainty with respect to future electricity demand. For the 10 years prior to 1973, electricity sales grew at an average annual rate in excess of 7 percent per year. Between 1973 and 1979, the annual rate dropped to 3 percent. Recent data covering the period 1979 to 1984 show a growth rate in electricity sales of just under 2 percent per year. Due to the recession and unusually mild weather, the level of electricity sales was actually lower in 1982 than in 1981. Many factors contribute to these changes in electricity growth, including rising electricity prices caused by differentially higher inflation in costs of new generating plants and higher costs for fuel used for electricity generation, conservation, and shifts away from energy-intensive activities. Given the complexity of factors that drive future demand levels and the uncertainty inherent in forecasting electricity growth, we believe that flexibility in planning is needed to respond to levels of demand that could be higher or lower than those projected.

The current trends in electricity demand differ from the projected longer term patterns. Generation rebounded in 1984 with 4.5 percent growth over 1983, but this growth must be viewed with caution. In the early months of 1983, electricity-intensive industrial activities did not grow as fast as the rest of the economy. These industries recovered more slowly than other parts of the economy. In addition milder than normal weather conditions in the early months of 1983 reduced the demand for space heating using electricity. The combined effects of lagging electricity-intensive industrial activity and mild weather resulted in weak growth in electricity sales during the early months of 1983. The resurgence in the growth of electricity demand experienced in 1984 would be less in percentage terms if 1983 levels had been normal. The demand levels in 1984 also reflect abnormally cold months in the early part of the year. The EIA projects electricity generation to grow by 2.8 percent in 1985 and 2.7 percent in 1986. The lower rate projected for 1985 is based on slower economic growth in 1985 than in 1984.

An important component in the future electricity supply is the available U.S. nuclear capacity. Figure 2 shows the discontinuance of requests for orders of nuclear plants since 1979. Plants currently under construction have experienced considerable delays in completion. EIA estimates indicate that about 49 gigawatts of nuclear generating capacity are scheduled to begin operation between 1985 and 1995. These plants account for 38 percent of the total capacity additions projected to come on line during this period. Figure 3 shows that nuclear power represents a significant portion of projected electricity generation in 1995, almost 19 percent. About 8 percent of all power supplied in 1995 is projected to be from nuclear plants coming into service over the next 10 years. As an aside, nuclear power has become firmly established as a U.S. power source for electricity generation. Surpassing hydropower in 1984, it is now the second most important power source in the utility industry, at 328 billion kilowatthours. U.S. nuclear electricity production in 1984 was so large that it would have met the entire U.S. electricity demand in 1949 (Figure 4).

There are many factors that govern the outcome of these projections, particularly those that affect individual regions of the country. The primary sources of fuels used to generate electricity, demand growth patterns, and transmission capabilities differ regionally and have varying impacts.

For example, imports from Canada have become a significant component of electricity supply in the northeastern United States. Although imports of electricity currently provide less than 2 percent of total U.S. requirements, it is likely that these imports will increase over the next few years. Electricity imported in the northeastern United States has grown from about 6 percent of the region's generation in 1980 to almost 13 percent in 1984. Recent forecasts estimate that in 1990 imported power from Canada could be as much as 20 percent of the total generation in the northeastern United States, assuming the power is not needed to meet requirements in Canada.

U.S. utilities purchase electricity from Canadian utilities (or from other U.S. utilities) when that electricity costs less than electricity they could generate themselves. U.S.-Canadian electricity trade is based on economic efficiency, seasonal diversity, system reliability and convenience, and entitlements to shared water resources. The existing transmission interconnections between U.S. and Canadian utilities improve the stability and reliability of the electric power systems in both countries and facilitate large, short-term transactions.

The EIA forecasts do not account for potential production of electricity by cogenerators or small power facilities (those units with capacities less than 80 megawatts). These sources of power could reduce generating requirements nationally by over 5 percent by the year 2000 according to some researchers.

Another source of uncertainty relates to bulk power sales where significant quantities of electricity could be made available over long distances. Transmission lines available today are being used to provide power to regions where higher cost generation sources can be replaced by lower cost generation from neighboring regions. Since these lines are being used to their maximum capacity, additional savings cannot be achieved currently. In the future, expanded transmission capacity could provide lower cost power to regions with higher costs as well as provide sources of electricity to regions where supplies are less than adequate.

Although EIA uses nameplate capacity ratings in its projections, plants may not achieve their nameplate ratings under actual operating conditions. It is estimated that by 1995 this difference in operating performance could increase capacity requirements by as much as 40 gigawatts.

As we look across the various economic growth cases, we find that some areas of the United States could experience difficulties in meeting demand reliably. In the EIA midcase scenario, the Western United States is projected to require capacity additions that are not currently under construction. The forecasts for this area of the country are especially sensitive to assumptions about the availability of transmission facilities that bring power into and throughout the area, including Canadian imports, availability of nonutility generation (including cogeneration and small power production), and programs to encourage demand management and conservation. To the extent that such sources are available, the difficulties in meeting electricity requirements could be mitigated. Since oil and natural gas are marginal sources of electricity generation (because of their high costs), these fuels could be used more extensively if difficulties are encountered. Other areas, New England, Mid-Atlantic, Southwest, and Central, are projected to use up more of their capacity cushions than the Nation as a whole and may experience difficulties after 1995, a period beyond our projections.

Under the assumption of high economic growth, where electricity is projected to grow at an average annual rate of 3.8 percent, all five of these areas could experience difficulties earlier than 1995. In the high-growth scenario, oil and natural gas consumption are projected to increase to meet additional demand requirements, in the process raising prices of electricity to consumers. In the low economic growth case, with 2.7 percent annual growth in electricity sales, the Western United States is still projected to require additional coal plants not currently under construction.

In summary, I would like to restate a number of points. Electricity generating capacity is adequate to meet our current needs. There may be reason, however, to be concerned about the future because of the advancing age of generating plants, the potential for demand growth greater than expected, and our continued dependence on capacity that burns expensive oil and natural gas. EIA projections show that the growth rate for electricity demand is expected to be higher than the rate of new capacity additions, indicating that the capacity "cushion" that exists today will be reduced in the future. If demand growth continues after 1995, additional capacity will be needed. Using the same assumptions for electricity growth and generation could require 35 to 145 gigawatts of additional baseload capacity from 1995 to 2000. Proper planning by the utilities will have to take place to ensure that facilities needed during this period will be available.

Individual areas of the country could experience problems in meeting projected demand if expected nuclear and coal capacity additions are not completed as scheduled, if demand grows more rapidly than expected, or if capacity additions are not started in time to meet demand. Under these conditions, oil and gas consumption could be higher than projected and consumers could face higher costs for electricity. Of course, if demand grows less rapidly than anticipated, oil and gas consumption could be lower than projected.

As with any forecasting endeavor, there are many reasons why the forecasts presented here may not be realized. Assumptions about growth in the economy, factors that affect consumption, world oil prices, adherence to current laws and regulations, as well as many other factors (such as successful completion of coal and nuclear plant construction, utilization rates for generating plants, and demand patterns) combine to form a unique set of conditions that strongly influence a particular outcome. The retirement of existing facilities, replacement of plants that are uneconomic to operate, and delays in beginning construction of announced plants are also factors that make the forecast uncertain. Although the EIA endeavors to produce forecasts that capture all factors that determine national level results, we have not represented conditions at the regional level in sufficient detail to have the same level of confidence. We do believe, however, that ranges developed from this analysis provide useful information for decisionmakers.

Table 1

Projected Average Annual Growth Rate in Electricity and GNP, 1985-1995

	Electricity Demand Growth (Percent)	GNP Growth (Percent)	Ratio of Electricity Demand Growth to GNP Growth
Low Economic Growth	2.7	2.0	1.4
Middle Economic Growth	3.2	2.7	1.2
High Economic Growth	3.8	3.4	1.1

Table 2

U.S. Generating Capacity, Projections for 1995 (Gigawatts)

	Low GNP Growth	Midcase GNP Growth	High GNP Growth
1995 Requirements	785	792	806
Existing	672	672	672
Inactive	–9	–9	–9
Operable	663	663 (a)	663
Retirements	0	0	0
Planned Additions	119	119 (b)	119
1995 Planned Capacity	782	782	782
Projected Shortfall	3	10	24

	(a) Existing Operable Capacity by Fuel Type	(b) Planned Capacity by Fuel Type
Coal	296	60
Oil & Gas	163	0
Nuclear	69	49
Hydroelectric / Other	84	8
Turbines	51	2
Total	663	119

Figure 1

Annual Change in Generating Capacity, 1960 - 1995

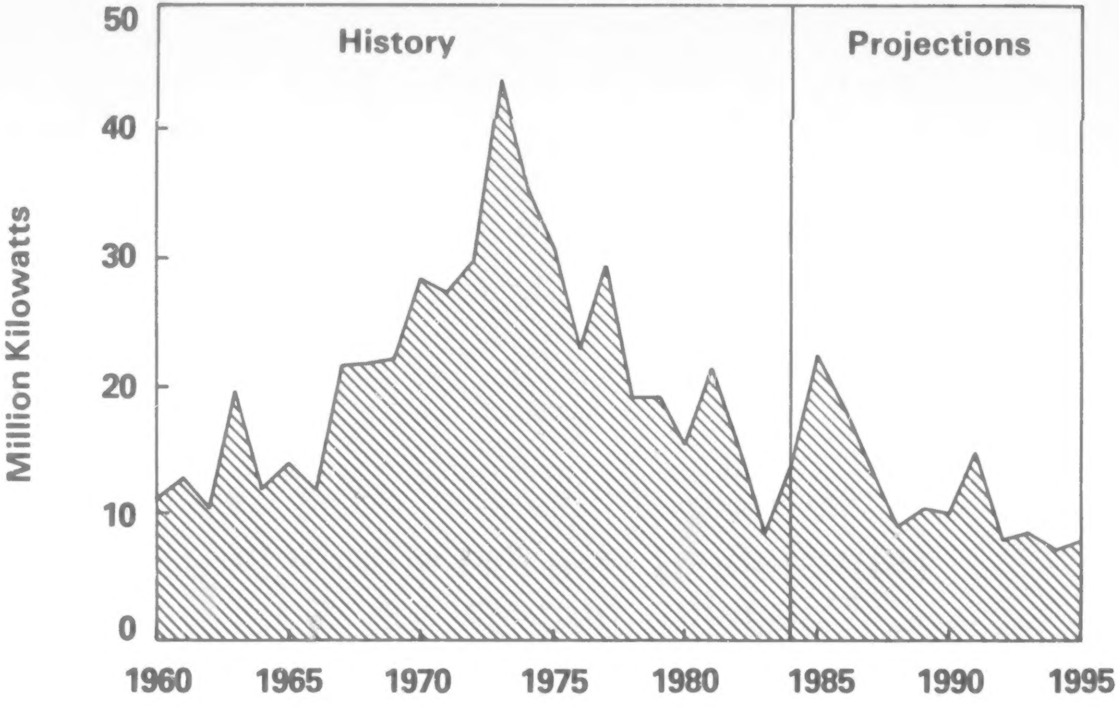


Figure 2

Status of Nuclear Power Plants 1973-1984

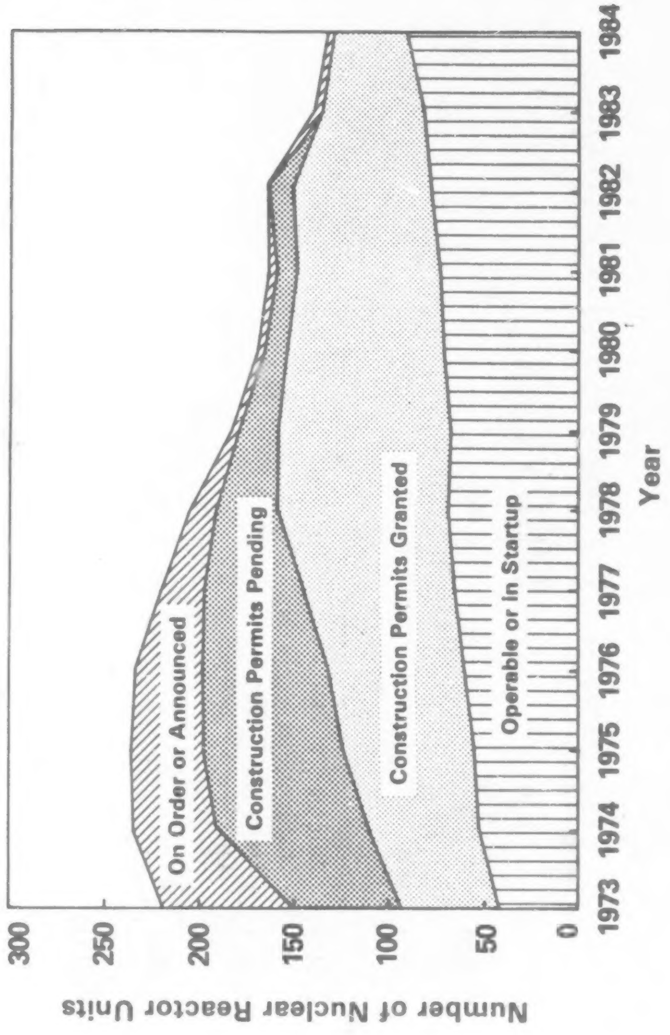


Figure 3

Sources of Electrical Supply, 1960 - 1995

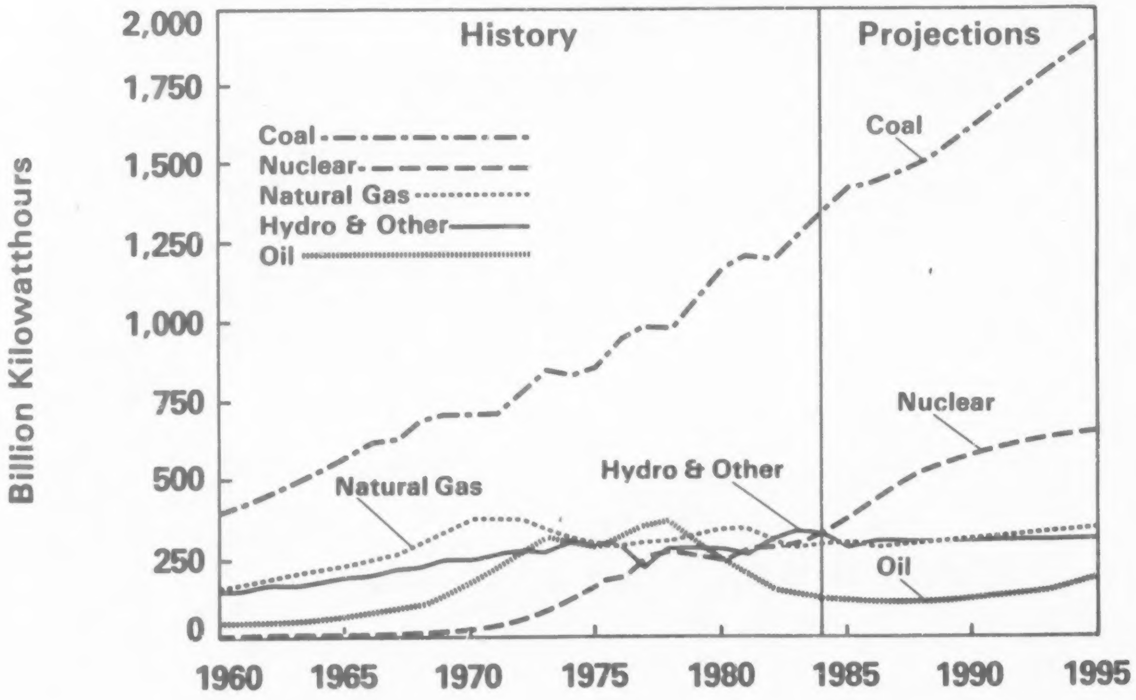
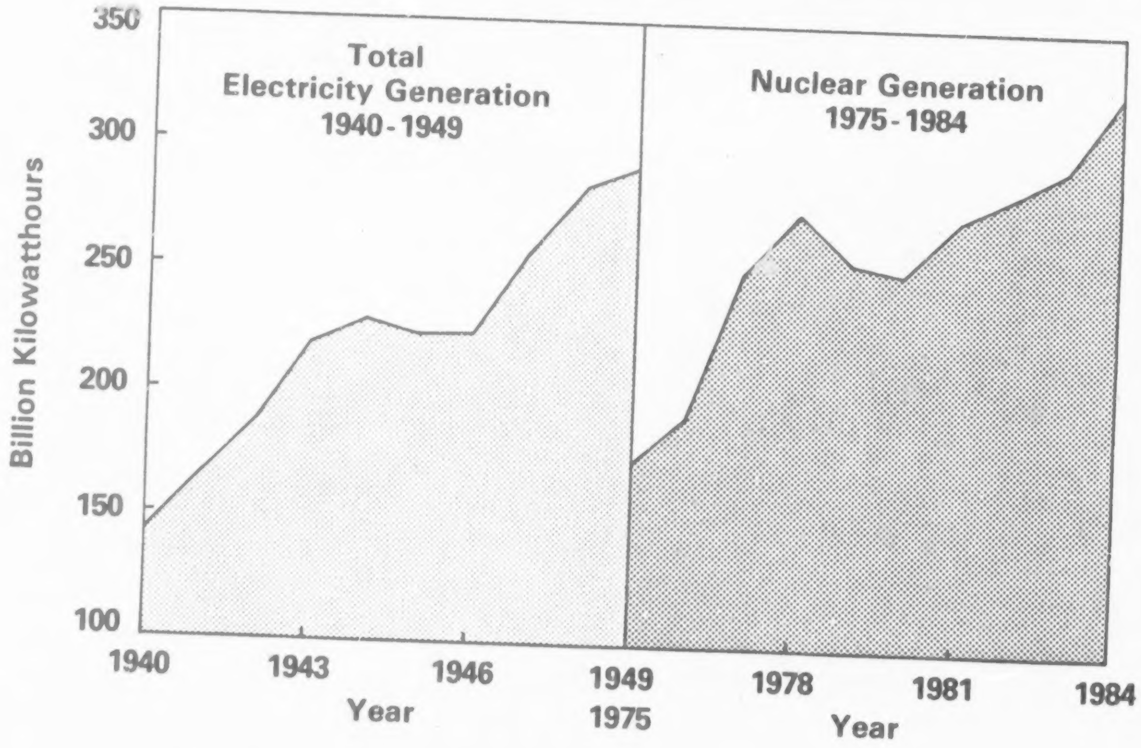


Figure 4

U.S. Total Generation, 1940-1949 & Nuclear Generation, 1975-1984



ADDENDUM TO JULY 25, 1985

TESTIMONY OF

DR. HELMUT A. MERKLEIN

ADMINISTRATOR, ENERGY INFORMATION ADMINISTRATION

BEFORE THE

COMMITTEE ON ENERGY AND NATURAL RESOURCES

UNITED STATES SENATE

ON

ELECTRICITY SHORTAGES IN THE 1990's

Addendum to Statement for the Record

Question 1:	Will serious shortages of baseload generating capacity occur on individual utility systems by the early 1990's?
Answer:	EIA performs analysis at the Federal region level and not at the individual system level. However, it should be recognized that there is a great deal of uncertainty involved in forecasts of this type. With this uncertainty in mind, EIA regional analysis projects that baseload capacity will be sufficient up to the early 1990's and possibly beyond. Under EIA demand growth assumptions, additional plants could be needed in the mid-1990's for which utilities have not made announcements or started construction.

Question 2: If such shortages occur, would each utility faced with such a shortage be able to prevent actual interruptions in service by obtaining additional supplies, such as combustion turbine generation or purchased power?

Answer: Replacement of baseload capacity could be accomplished if sufficient transmission capacity and generating capacity are available from neighboring systems. If these sources were not available, then a utility with insufficient baseload capacity would have to consider load management or delay of maintenance or installation of additional turbines. Turbines are economic in meeting peak load requirements but do not provide a cost effective way of satisfying baseload needs. It is estimated that new turbines could be installed in 2 years or less. Electricity generated by turbines would be far more costly than that generated from baseload equipment. In addition, turbines have greater reliability problems than equipment designed for baseload operations.

Question 3 : In your forecast of electric power supply, what are the assumptions relating to the retirement schedule for existing generating plants?

Answer : In our projections, EIA assumes no retirements of generating capacity between now and 1995. Utilities report retirement plans through 1994 to EIA. During this period, utilities have scheduled 19 gigawatts of capacity for retirement, most of which is uneconomic oil and gas steam capacity. During the period 1985 to 2000, utilities could retire from 40 to 60 gigawatts of capacity that will be 45 years old.

Question 4 : Do electric utilities have an incentive to minimize their investment in new central-station generating plants?

Answer : EIA has not analyzed disincentives that may exist for investment in new central-station generating technologies. Our projections of new baseload generating capacity are based on cost minimization behavior and reliability requirements. EIA assumes that utilities will earn their cost of capital. If utilities make decisions based on regulatory practice or different costs of capital than that assumed in this analysis, new capacity additions could be other than projected here.

Question 5 : If so, what are the contributing factors?

Answer : There are several factors that could contribute to utility decisions to avoid construction of new generating plants. These factors include delays in recovering capital expenditures (due to regulatory lag or phasing in of completed plants), disallowance of new plants in the rate base or allowed rates of return on investment that do not cover costs. Each of these factors increases the risk to investors and to the extent they exist, would result in utilities not building new plants.

Question 6 : To what extent have so-called "rate suppression" decisions by some state public utility commissions increased the risk of future shortages of electric generating capacity?

Answer : Rate suppression decisions tend to increase the uncertainty associated with completion of needed generating capacity. For utilities with significant expenditures already committed, decisions to not complete a project are less likely than for those utilities that have made announcements but have not spent appreciable sums for construction.

Question 7 : Who should have the responsibility for electric power supply planning, electric utilities or state regulatory commissions?

Answer : The Energy Information Administration does not take positions on policy matters. The EIA has no data and has not performed any analyses that could be used in answering this question.

The CHAIRMAN. Thank you very much. Dr. BODDE.

STATEMENT OF DR. DAVID L. BODDE, ASSISTANT DIRECTOR, NATURAL RESOURCES AND COMMERCE, CONGRESSIONAL BUDGET OFFICE, ACCOMPANIED BY THOMAS LUTTON, PRINCIPAL ANALYST; AND DAN CAROL, ANALYST

Dr. BODDE. Thank you, Mr. Chairman. I'd like to begin by introducing Dr. Thomas Lutton and Mr. Dan Carol to the committee. They are seated to my right, behind me. They are the gentlemen who have prepared the analysis we are presenting to you today.

This analysis takes a somewhat different approach to your questions than others might have taken. Rather than emphasize demand projections, we have analyzed the current financial conditions, how they came about, and what they imply for reliable and efficient electric service. Most of the industry has recovered from the acute financial distress of the 1970's and early 1980's. The circumstances of individual utilities, however, differ markedly. A number of companies remain under serious financial stress and a few may be candidates for bankrupty. The economic consequences of this are speculative, but it seems unlikely that bankruptcy by itself would cause interruptions in electric supply.

For the long term, the central issue is how to provide regulatory incentives for utilities to invest in the most cost-effective generation and transmission. As you noted in your opening statement, the problem is less the unavailability of electricity at any price than it is generation with equipment not well matched to the task.

Turning first to current financial conditions, most investor-owned utilities are in better financial condition today than at any time in recent years. Industrywide liquidity, measured by the ratio of cash-flow to dividend payments, stood at 2.7 in 1984, well above the 2.0 usually considered a prudent minimum. The recovery of the industry has been reflected in its common stock: by the end of May 1985, the market-to-book ratio for the industry as a whole stood at 108 percent, a marked contrast to the 73 percent of 1980.

The current health of the industry has grown out of a reversal of many of the factors that led the industry into decline in the 1970's. The economic recovery contributed to a revival in the demand for electricity. Many utilities finished the construction programs undertaken during the 1970's; other utilities canceled plants that had become too costly or that would have led to excessive reserve margins; and fuel prices and interest rates declined.

Despite these improved circumstances, the financial condition of a number of companies remains poor. In 1984, 14 of the largest 100 investor-owned utilities had cash-flow coverage of 1.5 or less. Currently, the common equity of eight utilites is valued by the market at less than 75 percent of their book value. In general, financially stressed companies such as these are trying to complete large construction programs that will yield reserve margins well above those needed for assured supply in the short term. These construction programs have been quite expensive, with capacity additions costing six to eight times more than originally projected. Most of this cost remains unrecovered from ratepayers, and its treatment is a central near-term issue for the electric utilities and the regulators.

If State regulators allowed full and immediate recovery of all construction costs incurred by the most distressed utilities, the first-year price increases in their service areas could range from 15 to 70 percent. Such increases would depress economic activity and lower the demand for electricity. But the State regulators could also withhold recovery of a large portion of this cost, finding it to be imprudent, incurred for unneeded facilities, or both. Utilities in poor financial condition might then lack the flexibility to accommodate such action and several have stated that it could force their bankruptcy.

The available evidence suggests that, in most cases, the outcome will be a division of costs between the ratepayers and the utilities that avoids bankruptcy but leaves these few utilities financially weakened. The long-term supply of electricity, however, is probably less sensitive to this allocation of costs than to the more general incentives provided by utility ratemaking.

The long-term concern with the utility industry is sometimes stated in terms of physical shortfalls in electric supply. It is misleading, however, to infer physical shortages simply by comparing capacity now in place with demand under various growth scenarios. To be sure, any growth in demand will eventually require additional generating capacity. But only the most shortsighted rate regulation would force an actual shortage by preventing a utility from either building its own capacity or purchasing electricity from a neighboring system. The real issue is whether current ratemaking practices encourage the most economic and timely additions to capacity.

For the Nation as a whole, reserve margins are currently above 35 percent, and should remain at this level for the next several years as plants now under construction are brought into service. But utilities must plan their investment around demand forecasts that look 10 or more years into the future. These forecasts suggest nationwide demand growth ranging from 1 to 4 percent, and individual systems may face even greater variation.

Power purchased from neighboring systems or cogenerators, together with load management can provide some flexibility by postponing the need to build new generating capacity. But as these options become exhausted, utility managers must decide whether to meet expected demand growth by beginning baseload plants well in advance of their service date, or whether to defer such additions until demand growth can be more clearly seen.

Either choice holds economic risk. A decision to build baseload capacity to meet projected demand can require major commitment of capital beginning many years before the service date of the plant. If the demand forecast was accurate, the baseload plant could provide the electricity at lowest cost. But actual demand less than that anticipated when the decision was made will create losses from the carrying costs of the underused investment. For example, the carrying charges for a $1 billion investment would be $100 million per year at a 10-percent interest rate.

On the other hand, a decision to postpone construction would risk meeting higher than expected demand with units not designed for baseload service. These units are less capital-intensive than baseload plants, and can be built more quickly, thus reducing the financial exposure of the utility. But in baseload service, these advantages are offset by significantly higher operation and fuel costs.

The task of regulation to allow utility managers to make such choices on the economic and technical merits without regulatory bias either for or against new construction. In many cases, current practice falls short of this ideal because the utility alone may be required to bear the carrying cost of excess capacity until it becomes used and useful. By contrast, the costs of inefficient generation tend to be more easily recovered through fuel adjustment and operating charges.

To the extent that this happens, economic decisionmaking is biased against incurring capital charges and toward fuel and operating expenditures. This bias could lead to a stock of generating equipment less suited to its task than if investments had been made under a more balanced regulatory treatment of risk.

The Federal role in utility finance has not been large. Indeed, the available evidence suggests that in most cases electric utilities and their regulators can reconcile the immediate cash-flows needs of the financially stressed utilities with the price increases imposed on ratepayers. Thus, the need for special Federal intervention in the near-term financial situation does not seem large. For the long run, however, the Congress might consider ways to improve competition and investment efficiency.

The first would be to review fuel use restrictions. The Fuel Use Act, as amended, generally prohibits the construction of new generating stations fueled by oil or natural gas. The deregulation of oil and gas markets, together with the prospect of further reductions in the price of these fuels, suggests that these prohibitions, especially for gas, be reconsidered.

In addition, Federal guidelines for State regulation might also be considered. These could be similar in concept to the standards that Public Utility Regulatory Policies Act of 1978 [PURPA] required States to consider—but not adopt. A variety of options are possible here, and these are reviewed in my formal statement.

We should note, however, that guidelines also have disadvantages. The ability of the Federal Government to influence State ratemaking has not been large, and it is uncertain how much real effect voluntary guidelines would have. Further, even voluntary guidelines could be seen as a Federal intrusion into the traditional prerogatives of State regulation and thus they could encounter resistance independent of their economic merit.

In summary, Mr. Chairman, the electric utility industry is in better financial condition today than in recent years. Its near-term problem—severe financial stress of a few utilities—is not likely to disrupt the supply of elecricity and the Federal role here does not seem large.

For the long run, lessons of the financially stressed utilities are that there are significant costs to overcapacity as well as to undercapacity. Utilities are responding to this by adopting strategies that emphasize flexibility and limit their capital exposure. This response may not lead to widespread physical shortages, but rate regulation that makes recovery of capital costs more uncertain than the recovery of fuel and operating costs could bias investment in the direction of less cost-effective equipment. Thus, the long-term issue is to provide regulatory incentives for utilities to use the mix of fuel and capital equipment that best match the economic realities of the coming decades.

That concludes my prepared statement.

[The prepared statement of Dr. Bodde follows:]

Statement of David L. Bodde
Assistant Director
Natural Resources and Commerce
Congressional Budget Office

before the
Committee on Energy and Natural Resources
United States Senate

July 25, 1985

This statement is not available for public release until it is delivered at 9:30 A.M. (EDT) on Thursday, July 25, 1985.

Mr. Chairman, I am pleased to appear before your committee to discuss the financial condition of the nation's electric utilities and what that condition implies for reliable and efficient electric service. Most of the industry has recovered from the acute financial distress of the 1970s and early 1980s. The circumstances of individual utilities, however, differ markedly. A number of companies remain under serious financial stress, and a few may be candidates for bankruptcy. The economic consequences of this are speculative, but it seems unlikely that bankruptcy, by itself, would cause interruptions in electric supply.

For the long term, the central issue is how to provide regulatory incentives for utilities to invest in the most cost-effective generation and transmission. The problem is less the unavailability of electricity at any price than it is generation with equipment not well matched to the task.

CURRENT FINANCIAL CONDITONS

Most investor-owned utilities are in better financial condition today than at any time in recent years. Industry-wide liquidity, measured by the ratio of cash flow to dividend payments, stood at 2.7 in 1984, well above the 2.0 usually considered a prudent minimum. The recovery of the industry has been reflected in its common stock: by the end of May 1985, the market-to-book ratio (the market value of common stock divided by the depreciated book value of the utility's assets) for the industry as a whole stood at 108 percent, a marked contrast to the 73 percent of 1980.

The current health of the industry has grown out of a reversal of many factors that led the utilities into decline in the 1970s. The economic recovery contributed to a revival in the demand for electricity; many utilities finished the construction programs undertaken during the 1970s; other utilities cancelled plants that had become too costly or that would have led to excessive reserve margins; and fuel prices and interest rates declined.

Despite these improved circumstances, the financial condition of a number of companies remains poor. In 1984, 14 of the 100 largest investor-owned utilities had cash flow coverage of 1.5 or less. Currently, the common equity of eight utilities is valued by the market at less than 75 percent of book value. In general, financially stressed companies such as these are trying to complete large construction programs that will yield reserve margins well above those needed for assured supply. At the same time, load growth over the next decade is forecast to be well below the industry average. Thus, growth in demand will not quickly relieve their excess capacity. These construction programs have also been quite expensive, with capacity additions costing 6 to 8 times more than originally projected. Most of this cost remains unrecovered from ratepayers, and its treatment is the central near-term issue for the electric utilities and their regulators.

THE NEAR-TERM ISSUE OF COST ALLOCATION

In most cases, state regulatory commissions allocate construction costs among ratepayers and stockholders. These regulators judge whether the construction expenditures were prudently incurred by the utility, and whether the completed plant is needed to meet current demand. Either test can lead a commission to exclude some or all of the cost of a completed plant from the rate base. The magnitude of these costs, however, makes this a difficult choice — both for the financially stressed utilities and for their rate commissions.

If regulators allowed full and immediate recovery of all construction costs incurred by the most distressed utilities, the first-year price increases in their service areas could range from 15 percent to 70 percent. Such increases would depress economic activity and lower the demand for electricity. But state regulators could also withhold recovery of a large portion of this cost, finding it to be imprudent, incurred for unneeded facilities, or both. Utilities in poor financial condition might lack the flexibility to accommodate such action, and several have stated it would force bankruptcy. If a bankruptcy occurred, the utility (or its creditors) would first file for reorganization under Chapter 11 of the bankruptcy code. A court-appointed trustee would then operate the company during the reorganization period to ensure continued electric service and company operations. The bankruptcy court would also decide how the utility's suppliers, creditors, and stockholders would be compensated, but the state regulators would probably have to approve any change in electric rates that might result. The economic outcome of these proceedings would be unique to each bankruptcy case.

Thus, financially troubled utilities and their regulators face a twofold problem. The rapid cost recovery that would relieve a utility's financial stress would also depress the demand for electricity in its service area, perhaps leading to further rate increases as fixed costs have to be spread over a smaller sales base. But postponing recovery of a large portion of these construction costs (or excluding them entirely) could leave the utility in financial peril and encourage the use of electricity by keeping prices artificially low.

The available evidence suggests that, in most cases, the outcome will be a division of cost between the ratepayers and their utilities that avoids bankruptcy but leaves these few utilities financially weakened. The long-term supply of electricity, however, is less sensitive to this allocation of cost than to the more general incentives provided by utility ratemaking.

THE LONG-TERM SUPPLY OF ELECTRICITY

The long-term concern with the utility industry is sometimes stated in terms of shortfalls in electric supply. It is misleading, however, to infer future shortages simply by comparing capacity now in place with demand under various growth scenarios. To be sure, any growth in demand will eventually require additional generating capacity. But only the most myopic rate regulation would force a shortage by preventing a utility from either building its own capacity or purchasing electricity from a neighboring system. The real issue is whether current ratemaking practices encourage the most economic and capacity additions.

Demand Forecasts and Investment Planning

For the nation as a whole, reserve margins are currently above 35 percent, and should remain at this level in the next few years as plants now under construction are brought into service. But utilities must plan their investments around demand forecasts that look 10 or more years into the future. These forecasts suggest nationwide demand growth ranging from 1 percent to 4 percent, and individual utilities may face even greater variation. Power purchased from neighboring systems (or cogenerators) together with load management can provide some flexibility by postponing the need to build new generating capacity. But as these options become exhausted, utility managers must decide whether to meet expected demand growth by beginning baseload plants well in advance of their service date, or whether to defer such additions until demand growth can be more clearly seen.

Either choice risks economic losses. A decision to build baseload capacity 1/ to meet projected demand can require a major commitment of capital beginning many years before the service date of the plant. If the demand forecast was accurate, the baseload plant could provide the electricity at a lower cost than any other alternative. But actual demand less than that anticipated when the decision was made will create losses from the carrying costs of the underused investment. For example, the

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1. The supply options available to a utility are not limited to very large (over 1,000 MWe) central station powerplants, but also include highly efficient smaller or modular units. Some of these may be equally capital intensive as measured by the cost of a kilowatt of capacity, but their size reduces the utility's financial exposure. See testimony of Dr. Richard E. Rowberg, Office of Technology Assessment, before the Committee on Energy and National Resources, United States Senate, July 25, 1985.

carrying charges for a $1 billion investment would be $100 million per year at a 10 percent interest rate.

On the other hand, a decision to postpone construction would risk meeting higher than expected demand with units not designed for baseload service. These units are less capital intensive than baseload plants and can be built more quickly, thus reducing the financial exposure of the utility. But in baseload service, these advantages are offset by significantly higher operation and fuel costs.

Thus, investment decisions in the electric utility industry require a balancing of risks. 2/ The task of regulation is to allow utility managers to make such choices on their economic and technical merits without regulatory bias either for or against new construction. In many cases, current practice falls short of that ideal.

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2. Simulations of the relative economic cost of excess capacity versus less efficient capacity suggest both to be comparable in size. Falling prices for fossil fuels, however, could significantly reduce the penalties from inefficiency.

Regulation and Investment Decisions

Ratemaking can influence a utility's decision to invest by making the recovery of construction costs more uncertain than the recovery of fuel and operating costs. Construction charges are often held in a separate account outside the rate base rather than reflected in the price of electricity. Once the plant is placed in service, the accumulated amount, together with a return earned on it, is placed in the rate base for recovery.

This practice can lead to several difficulties. Electricity consumers are first shielded from one price effect of their consumption — the need for new capacity — and later presented with sharp rate increases. At the same time, the utility's capacity to make additional investments is constrained by cash flow limitations and the recognition by investors that business risk has been increased by the lower quality of earnings.

The most important issue, however, is the implicit treatment of risk. If the demand for electricity proves to be less than that forseen when the plant was begun, the utility may be required to bear the carrying costs of the excess capacity until it becomes "used and useful". By contrast, the costs of less efficient generation tend to be more easily and quickly recovered through fuel adjustment and operating charges. To the extent that this happens, economic decisionmaking is biased against incurring capital charges and toward fuel and operating expenditures. This could lead to a stock of generating equipment less suited to its task than if the investments had been made with a more balanced regulatory treatment of risk.

THE FEDERAL ROLE

Traditionally, the major role in providing electricity has been left to the investor-owned utility companies and their state regulators. The available evidence suggests that in most cases these institutions can reconcile the cash flow needs of the financially stressed utilities with the price increases imposed on ratepayers. Sales of electricity among utility systems has increased markedly, thus helping to balance overcapacity with the demand for economic generation; and, incipient mergers may strengthen the financial resources of some utility systems. Thus, the need for special federal intervention in the near-term financial situation does not seem large. For the long run, however, the Congress might consider ways to improve competition and investment efficiency.

Fuel Use Restrictions. The Fuel Use Act, as amended, generally prohibits the construction of new generating stations fueled by oil or natural gas. The deregulation of oil and gas markets, together with the prospect of further reductions in the price of these fuels, suggests that these prohibitions be reconsidered. The removal of the gas restriction would yield environmental benefits, stimulate interfuel competition, and encourage utility investments based on the economics of electricity production. Removing the oil restriction as well would further increase interfuel competition, but would also leave the utilities and their customers more vulnerable to any future disruptions in oil supply.

Federal Guidelines. Federal guidelines for state regulation might also be considered. These could be similar in concept to the standards that the Public Utility Regulatory Policies Act of 1978 required states to consider (but not adopt). The guidelines could suggest state approaches to cost-effective investment through more balanced treatment of the risks of excess capacity and less efficient generation.

For example, state regulatory commissions could consider better ways to share the responsibility for predicting demand. States could approve (or disapprove, as appropriate) plant costs at several stages in the construction process. This staged review would lower investment risk by guaranteeing eventual cost recovery of the approved portion of the project, even if these costs were not immediately included in the rate base. It would forewarn of changes in demand growth and enable the utility to either abandon construction or mothball the plant for future use if conditions warrant. The State of Indiana has taken this approach in a law enacted in April of this year. Alternatively, some portion of prudently incurred construction costs could be included in the rate base prior to actual service.

Other guidelines might allow the utility a higher rate of return on cost-effective investments. Where new capacity results in net "avoided costs," some portion of the savings could be reflected in utility earnings, thus giving these companies a direct financial stake in least-cost generation. This approach might better balance risk and reward in states seeking ways to give their utilities greater responsibility for the economic outcome of investment decisions. Finally, the use of fuel-adjustment clauses could be amended to encourage fuel-switching investments.

On the other hand, the ability of the federal government to influence state ratemaking has not been large, and it is uncertain how much real effect voluntary guidelines could have. Further, even voluntary guidelines could be seen as a federal intrusion into the traditional prerogatives of state regulation, and thus encounter resistance independent of their economic merit.

CONCLUSION

In summary, Mr. Chairman, the electric utility industry is in better financial condition today than in recent years. Its near-term problem—the severe finacial stress of a few utilities—is not likely to disrupt the supply of electricity, and the federal role here does not seem large.

Over the longer term, there is growing evidence that the utility industry is responding to an increasingly risky business environment by adopting strategies that emphasize flexibility and limit capital exposure. This response is unlikely to lead to widespread physical shortages. However, rate regulation that makes the recovery of capital costs more uncertain than the recovey of fuel and operating costs could bias investment in the direction of less cost-effective equipment. Thus, the long-term issue is to provide regulatory incentives for utilities to use the mix of fuel and capital equipment that best match economic realities.

The CHAIRMAN. Thank you very much.
Dr. Rowberg.

STATEMENT OF DR. RICHARD E. ROWBERG, PROGRAM MANAGER, ENERGY AND MATERIALS PROGRAM, OFFICE OF TECHNOLOGY ASSESSMENT, ACCOMPANIED BY PETER BLAIR, PROJECT DIRECTOR

Dr. ROWBERG. Thank you, Mr. Chairman, for the opportunity to testify before your committee this morning. With me is Dr. Peter Blair, Project Director of our most recent study, New Electric Power Technologies: Problems and Prospects for the 1990's.

The most critical legacy for the electric utilities from the financially troubling 1970's and early 1980's is the uncertainty in demand growth, which is now the critical factor in utility planning. Because of this uncertainty, utilities find it difficult to start new power projects, because there is the possibility that they will not be needed when completed. There is an incentive to avoid the risk of too much capacity, in favor of the risk of too little capacity.

To gain a perspective on why demand is uncertain, it's useful to examine some of the sources of that uncertainty. We can do this by using an engineering or bottom-up analysis which examines the technical and institutional factors and trends that determine electricity use.

In the industrial sector, future demand will be determined primarily by three factors, each of which contains its own uncertainties. These are the growth rates of industries that are heavy users of electricity, efficiency improvements in existing electric equipment and the penetration of new electric-using technologies primarily in the area of process heat.

These factors, in turn, are dependent on economic growth, technology development, international competition, investment climate, and the expected price of electricity in competing fuels.

Principal determinants of future use in the residential sector are the rate of new household formation and a penetration rate of electric appliances. The former depends on changes in population and personal and economic considerations about household size, while major appliance use—primarily electric water and space heating—will depend on the relative prices between electricity and natural gas, the expected changes in electricity price alone, and cost of more efficient appliances and technology development.

In addition, household electricity demand will be greatly affected by increased competition from natural gas in the residential energy market.

The primary determinants in the commercial sector are trends in floor space and penetration of equipment using electricity. There are many factors that will influence these trends, including the rate of economic growth, expectations about the price of electricity, competing energy sources, equipment, capital costs and technology development.

By aggregating these technical, economic and demographic trends, we estimate that electricity demand would grow between 1½ and 4 percent per year, on average, over the next 15 years.

In converting this range to capacity requirements, plant retirement schedules also need to be considered. By 1995, 60 percent of the nation's electric utility generation capacity will be older than 20 years and 29 percent will be older than 30 years. Because these plants are more thermally efficient and larger than the plants built prior to 1950 that are now being retired, however, utilities have greatly increased plant betterment and life extension efforts.

As a result, it is likely that the lifetimes of plants reaching 30 years of age before the year 2000 will be extended to 40 or perhaps 50 years.

Combining retirement rates with our estimates of electricity demand, we arrive at an estimate of the range of capacity rquirements that would be needed by 1995. At the lower end, a growth rate of 1½ percent per year, and a 50-year powerplant lifetime, no new plants beyond those currently being completed would be needed to meet capacity requirements and maintain a 20 percent reserve margin.

At the upper end, however, with a demand growth of 4 percent per year and a 40-year power plant lifetime, we would need nearly 165,000 megawatts of new capacity by 1995 in addition to that now under construction.

The range of possible capacity requirements clearly shows the enormous burden placed on utility planners by demand uncertainty. If utilities are to cope with this uncertainty, they must take steps to expand their options. Many utilities are considering several options that can defer large-scale powerplant commitments and increase their planning flexbility. This path, however, should not necessarily inhibit utilities from meeting future demand, provided that they are not constrained from being able to exercise these options to the extent needed.

Existing policy and technical consideration, however, do create some constraints. This is particularly true about the availability of both conventional and new generating technologies which have the potential of flexibly meeting future demand and increasing the clean and efficient use of abundant domestic energy resources.

For new technology, accelerating developments so that utilities would have a greater array of choices in the 1990's requires resolution of cost and performance uncertainties through advanced commercial demonstration projects for more focused research and development, and attention to regulatory concerns and to quality construction, to minimize lead times for initial ventures of clean coal technology.

Other actions that could assist, include allowing to utilities the full benefits under the Public Utility Regulatory and Policy Act and removing restrictions on the use of natural gas by utilities for new large powerplants.

For conventional plants, the absence of a nuclear option also will limit utility capabilities to deal with future uncertainties. Resolution of management, cost, and regulatory problems and changes in the technology—primarily development of smaller standardized reactors which emphasize inherent safety features—will be necessary if this option is once again to be one of the choices available to utilities.

While it is not likely that most utilities will face capacity limitations for the rest of the 1980's, the uncertainty that does exist, particularly in the 1990's, makes it quite important that utilities move in the direction of enhancing their planning flexibility and that a wide range of demand management and electricity supply choices are available to utilities.

That completes the summary of my statement, and I would be glad to answer any questions.

[The prepared statement of Dr. Rowberg follows:]

Testimony of Richard E. Rowberg
Program Manger, Energy and Materials Program
Office of Technology Assessment

before

Committee on Energy and Natural Resources
United States Senate

July 25, 1985

Mr. Chairman, thank you for the opportunity to testify before your Committee this morning. I will present some of OTA's findings about future electricity demand and the ability of the nation's electric utilities to plan in the face of considerable uncertainty. These findings are from two recent OTA studies, Nuclear Power in an Age of Uncertainty, which we released in February 1984, and New Electric Power Technologies: Problems and Prospect for the 1990s, which was released yesterday. With me is Dr. Peter Blair, the project director on the latter study.

Since 1973, the growth rate for electricity demand, which averaged about seven percent per year from 1960 to 1972, has averaged less than 2.5 percent per year. Because a decline of that size was not forecast -- even when it first became clear that electricity prices were increasing -- utilities found themselves constructing or planning to construct electric generation capacity far in excess of that which would be needed. Further, because of the long planning and construction times for central station powerplants, utilities could not respond to the changes in demand as quickly as consumers made those changes in response to higher prices. The result was a large surplus of capacity for most of the nation's utility systems even though a large number of powerplants in various stages of development have been cancelled since 1973. The eroding revenue base accompanying declining demand growth and the increasingly costly construction programs underway left the industry for the most part struggling financially.

While most utilities have recovered from this financial stress, the scars remain. The most critical legacy of that period is the uncertainty in demand growth. While it is nearly certain that the days of growth at seven percent per year will not return, growth over the next 15 years, in our view, will be somewhere between 1.5 and 4 percent per year. This range, combined with uncertainties in powerplant retirement age, leads to enormous differences in new capacity requirements -- as much as 165,000 MW by 1995. It is this uncertainty that is the critical factor in utility planning. If the growth rate were fairly certain in the minds of all parties of interest -- utilities, ratepayers, financial community, public utility commissions, etc. -- utilities would find planning much more straightforward. Under these circumstances, even larger growth rates -- say 4 to 5 per cent per year -- probably could be accommodated, although securing necessary financing and regulatory approval might still be difficult. Because demand growth is so uncertain, however, planning is much more complex. Utilities find it very difficult to start new power projects because there is the possibility that they will not be needed when completed, leading to a renewal of financial difficulties. None of the interested parties is willing to let that happen, so there is a strong incentive to avoid the risk of too much capacity in favor of the risk of too little capacity. We have long been concerned about the cost of not having enough capacity, but the financial troubles faced by utilities in the 1970s showed that there was also a high cost of having too much.

Utilities are attempting to respond to these uncertainties by increasing their ability to forecast demand, and by taking a number of steps concerning demand management and electricity supply to shorten the time needed to accommodate unforeseen changes in demand. Basically, utilities are attempting to become more flexible. We have examined a number of issues concerning these efforts and this testimony describes our findings.

To gain a perspective of why future demand is uncertain, it is useful to examine the sources of that uncertainty. We carried out just such an analysis in our study on nuclear power. In that report we undertook both a macroeconomic or "top-down" analysis of future electricity demand, and an engineering or "bottom-up" analysis. The former looks at the way electricity demand interacts with economic variables such as GNP, and the price of electricity and competing energy sources. The latter examines the technical and institutional factors and trends that determine electricity use. While both methods are important in trying to estimate future demand, the engineering approach can isolate the sources of uncertainty. This information is necessary if demand forecasting is to be improved.

Industry

Of the three sectors of the economy, residential, commercial and industrial, the latter uses the largest fraction of electricity generated in the U.S., about 38 percent. This sector is also the most complicated because of the wide array of uses and users. Future demand will be determined primarily by three factors, each of which contains its own uncertainties. These factors are the growth rates of industries that are heavy users of electricity, efficiency improvements in existing electric equipment, and the penetration of new electric using technologies,

Currently, the major industrial users of electricity are the metal products industry, commodity chemicals, petroleum refining, pulp and paper, and cement. The output of many of these industries is not expected to grow as rapidly as total U.S. industrial production. An OTA study on industrial energy use projected growth rates for product output of steel and petroleum refining well below that of GNP for the rest of the century. Even chemicals, which is expected to grow faster than GNP, will shift away from production of electric intensive bulk chemicals to higher value-added specialty chemicals which require less energy per unit output. These growth rates could vary, however, because of possible changes in economic growth and international competition. Even fractional percentage point changes in output growth rates will have a major effect on the amount of electricity that is required.

Efficiency improvements are underway and may continue in the two major functional uses of electricity in industry, motor drives and electrolysis. About 50 percent of all electricity in industry is used for motors. While the use of motors is expected to increase at about the rate of industrial growth, electricity use per motor could decline anywhere from 5 to 20 percent. The application of solid state control devices, which allow motor speed to track load, will cause operating efficiency to increase substantially. Electrolysis, too, could see efficiency gains of up to 20 to 30 percent. Gains of this magnitude are probably necessary if domestic aluminum production is to remain internationally competitive. Just what efficiency gains will be acheived are another source of uncertainty. Investment decisions in efficiency depend on investment climate, technical developments, the firm's competitive position, and the expected price of electricity over the economic life the investment. Changes in the outlook of any of these can push electricity demand up or down by a significant amount.

Electric process heating in industry currently accounts for only about 10 percent of current uses of electricity. There is considerable potential for this to increase, however, as new electric process heating techniques are developed that make use of electricity's capability for precise control and its ability to produce very high temperatures. Furthermore, the largest fraction of all energy used in industry is for process heat. Therefore if industrial electricity demand is to grow substantially, it will due to greater process heat applications.

One application, electric arc steelmaking, already accounts for a substantial fraction of total steel production in this country and is expected to become even more so. In addition, other technologies such as plasma reduction and melting processes for primary metals production, induction heating for shaping and forging, and electric reheating of metals could all become important industrial processes and significant users of electricity in the years ahead. Furthermore, these applications promise to improve industrial productivity. Other processes, such as laser materials processing and robotics, also will be important from an industrial production perspective, but will not be major users of electricity before 2000. While the potential is large for these technologies, the long time needed for major capital stock changes and the current outlook for primary metals production in this country mean that the effect of these technologies on electricity demand will not began to show up in a major way until the end of the 1990s. Again this could be altered if technology development were to accelerate or slow, if the price of competing fuels were to change dramatically with respect to electricity, and the investment climate were to change.

Finally, the role of cogeneration must be considered in examining the demand for purchased electricity by industry. To the degree that cogeneration is able to supply electricity to an industrial firm, the growth rate for purchased electricity from utilities will diminish. The eventual contribution depends primarily on the cost of electricity, the availability of natural gas, and the effectiveness of conservation programs in limiting industrial steam requirements. Again, each factor contains a degree of uncertainty which will compound when estimating the effect of cogeneration on electricity demand.

Residential

The residential sector currently uses about 34 percent of nation's total electric energy production. Principal determinants of future use are the rate of new household formation, household size, and the penetration rate of electric appliances. The formation rate over the past several years has been greater than population growth reflecting a trend towards smaller households. This trend is likely to continue, but demographic factors indicate that household formation rate is likely to drop. How much is hard to determine because of the many personal and economic factors involved. In the early 1990s, the rate should slow even more as the population continues to age. Only near the end of the century are the demographics favorable to an increase in the household formation rate. Because demand for electricity in this sector is so dependant on the formation rate, even small changes can affect demand substantially.

Residential appliances which use the most electricity are refrigerators, water heaters, air conditioners and space heaters. Of these four, only electric water and space heating offer the possibility of substantial growth because only 30 and 16 percent of the nation's homes, respectively, currently use electricity for these purposes. For the last several years about 50 percent of the new homes have been heated with electricity, and continuation of that rate would add substantially to the growth rate of residential electricity demand. There is less potential with air conditioning, because it is now much closer to saturation in both existing and new homes.

There are factors, however, which can reduce household electric demand growth. First is the extent that improvements in building, appliance and lighting efficiency are adopted, and second is that natural gas is becoming increasingly competitive in the residential energy market. Despite the large improvements in energy efficiency that have already occured, much more is possible. Specifically, the average efficiency of appliances and lighting sold in 1982 was about 50 percent below that of the most efficient on the market. Further, the payback period of the extra cost for the higher efficiency at 1982 electricity prices was about 4 to 8 years. If electricity prices stabilize or drop over the next several years, the incentives for investing in greater efficiency would decline, although by an uncertain amount. The competition from natural gas will also cut into the potential for electric sales. Currently, aggressive marketing by natural gas companies is not only reducing the rate of new homes heated with electricity, but also is stimulating homes originally heated with electricity to convert to natural gas heat.

When penetration rate, efficiency improvement, and natural gas competition trends are combined, considerable uncertainty arises about the net effect on electricity demand. Relative prices between electricity and natural gas, the expected changes in electricity prices alone, costs of more efficient appliances, and technology developments will determine whether there is an increase or decrease in the installation rate of major electric appliances and the electricity requirements of those appliances. These trends also vary widely by region which will add to the regional disparity in electricity demand from the residential sector.

Commercial

Finally, the commercial sector uses about 24% of all electricity produced in the U.S. Of the three sectors, commercial demand for electricity has been growing the fastest since 1973. The primary determinants are the growth in floor space and penetration of equipment using electricity. Commercial building square footage is forecast by the Energy Information Agency to continue its 1974-1979 growth rate to 1995 at least, about 2.7 percent per year. This forecast is subject to considerable uncertainty, however, since there are little data on construction rates of commercial buildings.

Electricity use per square foot could continue to grow because only about 25 percent of existing buildings are heated with electricity while nearly 48 percent of new buildings are equipped with electric heat. About 80 percent of all commercial buildings have some air conditioning, indicating only a modest potential for increased electricity use per square foot from this source. Office equipment is growing rapidly in commercial buildings -- primarily computational facilities. It is too soon, however, to accurately assess how this growth will effect electricity demand because use patterns have not yet been analyzed. Is is expected, however, that rapid growth in office equipment will add to demand directly, and increase cooling loads.

Efficiency improvements also may continue in commercial buildings. The potential for savings by building retrofit is less well known than for residential buildings. Commercial buildings are very diverse in size, shape and type, and little documentation exists on energy savings in existing units. Electronic control systems, however, are being used in commercial building to provide more efficient operation of the building's mechanical and lighting systems. The electric power requirements of office equipment is also declining as computer technology adcvances. Newer computers with the latest in solid state circuitry and display technology use only a small fraction of the power needed by early units. There is also considerable potential for greater efficiencies in lighting, a large user of electricity in commercial buildings. Finally, natural gas is aggresively pursuing business in the commercial sector at the expense of electricity.

As with the residential sector, there are many factors, each with their own uncertainties, that will influence the trends in commercial buildings which determine electricity demand. The rate of economic growth, expectations about the price of electricity and competing energy sources, equipment capital costs, and technology development are the principal factors that will determine additions of building space, and the choice and efficiency of major energy using equipment in these buildings.

By aggregating these technical, economic and demographic trends, with their uncertainty, one can estimate demand growth for electricity. The more precision with which these trends can be determined, the narrower will be the resulting range of demand growth uncertainty. In addition, these trends are regionally dependent. For example, in those parts of the country where residential and commercial growth is most rapid, electricity demand is likely to grow faster than the national average. Similarly, if a region is experiencing a decline in electric intensive, manufacturing industries, demand growth will probably be quite low. In our study, we estimated the range of electricity demand that would result from currently accepted projections of these technical and economic trends on a nationwide basis. Considering all of these factors, we concluded that electricity demand would grow between 1.5 and 4 percent per year on the average over the next 15 years. This wide range reflects the uncertainty inherent in all of the technical and economic trends.

We next turn to capacity requirements. In addition to demand growth rates, one other important factor needs to be considered. This is age of our existing powerplant inventory. Up to now, replacement of existing powerplants has always been a small fraction of yearly additions to capacity. As growth rates slow, however, and the existing stock gets older, this could change. By 1995, 60 percent of the nation's electric utility generation capacity will be older than 20 years and 29 percent will be older than 30 years. The latter has traditionally been the economic lifetime of powerplants and at that age, most powerplants in this country have been either completely retired or confined to reserve status.

This situation will change, however, for two reasons. The first is the large number of plants that will reach age 30 by 2000. The second is that most of these plants are more thermally efficient and larger than the plants built prior to 1950 that are now being retired. As a consequence, utilities have greatly increased plant betterment and life extension efforts. Our analysis shows that this can be an attractive alternative to building new capacity, expecially if plant capacity can be increased during the betterment process. As a result, it is likely that the lifetimes of plants reaching 30 years of age by 2000 will be extended to 40 or perhaps 50 years.

It is important to note that regional variation is also important concerning powerplant life extension and betterment. The amount of installed capacity reaching age 30 in the 1990s is greatest in the Mid-Atlantic, Southwest, Gulf and Western States. Those regions with a high percentage of capacity in this situation will have considerable opportunity to exercise the plant betterment option, but they may also increase reliability risk.

Combining plant retirement schedules with our estimates of electricity demand, we can determine a range of capacity requirements needed by 1995. At a demand growth rate of 1.5 percent per year and a 50 year powerplant lifetime, no new power plants, beyond those currently being completed, will be needed by the year 1995 to supply electricity demand and to maintain a 20 percent reserve margin. (Total capacity in 1993 according to the North American Electric Reliability Council (NERC) is expected to be 714,000 MW.) At a demand growth rate of 4 percent per year with a 40 year powerplant lifetime, we would need nearly 165,000 MW of new capacity -- that is in addition to the 714,000 MW -- by 1995 to meet demand and maintain the 20 percent reserve margin. The difference in requirements between the two futures would more than double by the year 2000.

We can also get a picture of the regional variation by examining each of the NERC regions under various load growth assumptions. In this case we included a 20 percent reserve margin, but did not assume any powerplant retirements. The results (attached figure) show that by 1993 capacity surpluses would exist in all regions for growth rates of 1.5 percent per year, but deficits would develop in some regions -- Texas and the upper midwest -- if growth rates reached 2.5 percent per year. At 3.5 percent per year, deficits would appear in five of the nine regions, and at 4.5 percent per year there would be capacity shortfalls in all regions. The range of possible capacity requirements clearly shows the enormous burden placed on utility planners by demand uncertainty.

If utilities are to cope with this uncertainty, they must take steps to expand their options. Prior to the 1970s, maintaining power system reliability was treated as a prescribed constraint and utilities had little difficulty earning their regulated rate of return on investment while achieving steady reductions in the cost of electricity by building larger, less capital-intensive powerplants. Because of the uncertain investment climate now facing utilities, however, many are avoiding large-scale plant commitments and are considering many options that can defer such commitments and increase their planning flexibility. While continuing to rely primarily on conventional technologies, utilities are seeking significant modifications in those technologies. In particular they are interested in smaller, more modular versions of conventional central station powerplants, and they are examining environmental and efficiency improvements for these plants. Other options include the life extension and rehabilitation of existing generating facilities we mentioned above, increased purchases from and shared construction programs with other utilties, increased reliance on load management and conservation, and new, smaller scale generating technologies using both conventional and alternative energy sources. These options offer utilities the prospects of increased planning flexibility in attempting to accommodate future demand, regulatory and financial uncertainties.

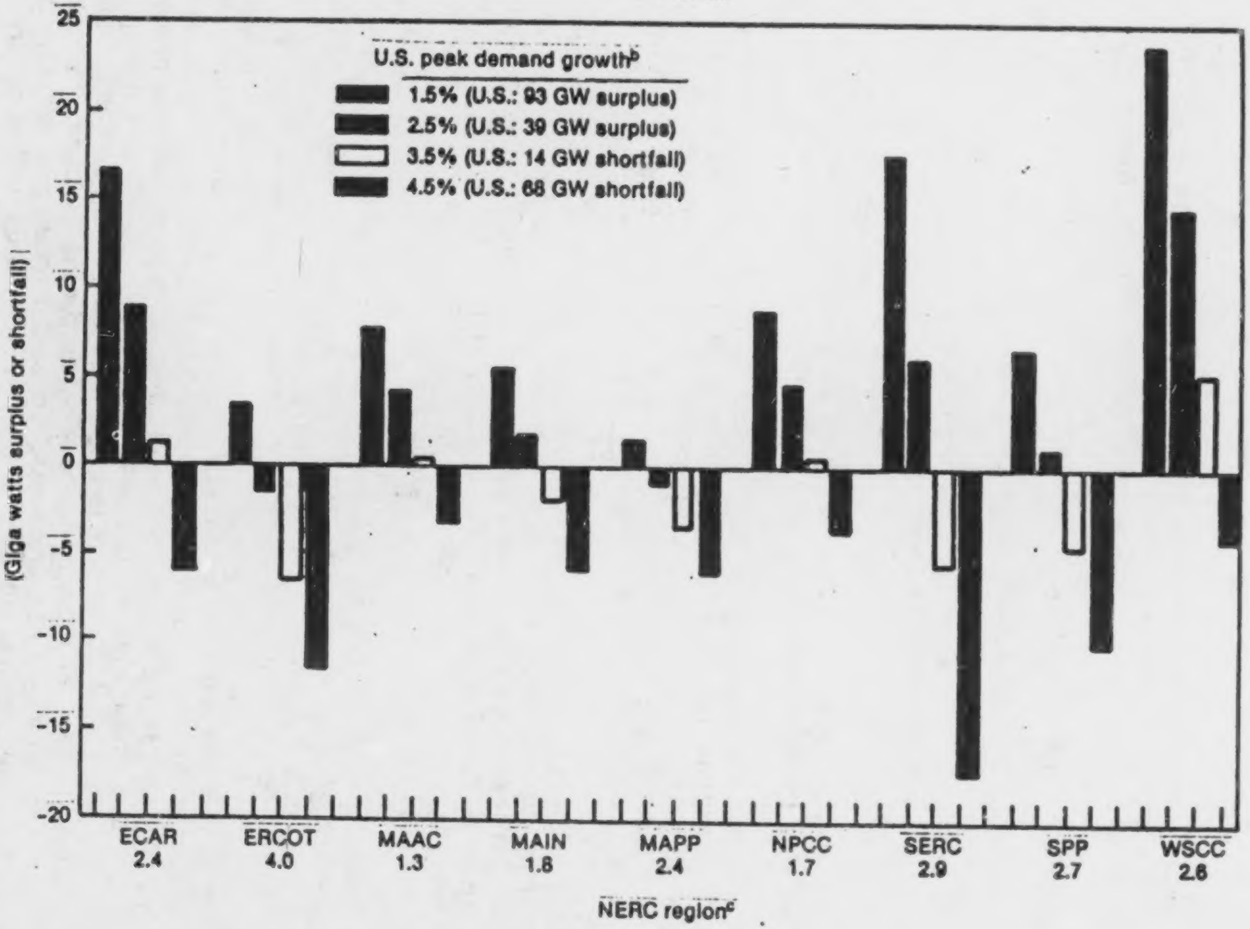
As a group, these options also define a path which is designed to minimize capital exposure and financial risk for a utility. This would occur even though some of the options -- namely those concerning generating technologies -- are likely to be more capital intensive, i.e., dollars per kW, than very large unit size (about 1000 MW) central station power plants. Taking this path, however, should not inhibit utilties from meeting future demand provided that they are not constrained from being able to deploy these choices to the extent needed.

Existing policy and technical considerations, however, do create some constraints. This is particularly true about availability of conventional and new generating technologies which have the potential of flexibly meeting future demand and increasing the clean and efficient utilization of abundant domestic energy resources. Our analysis indicates that with uncertain demand growth, the cash flow benefits of such plants can be considerable. Conventional technologies include smaller, modular, pulverized coal boilers with enhancements to reduce emission, combined cycle combustion turbines, and, possibly, small nuclear plants. The newer, less traditional technologies include integrated gasification combined-cycle plants, atmospheric fluidized bed combustors, advanced geothermal plants, fuel cell powerplants, solar thermal and photovoltaic facilities, and wind.

This last set of technologies is not likely to be ready for substantial deployment in the 1990s for a variety of reasons. Making them available will require resolution of cost and performance uncertainties through advanced commercial demonstration projects or more focused Federal research and development, and attention to regulatory concerns and quality construction to minimize lead times for initial commercial plants. Accelerating the development of these technologies so that utilities would have a greater array of choices in the 1990s could be assisted by several actions. Among these are: 1. establishing cooperative agreements among utilities, public utility commissions and the Federal government to provide support for advanced demonstration projects; 2. allowing full benefits under the Public Utility Regulatory Policy Act to utilites; and 3. removing restrictions on the use of natural gas by utilities for new, large powerplants. In addition, development would be maintained for a number of renewable technologies if the some form of renewable energy tax credits were continued for the next few years.

Of the conventional technologies, absence of a nuclear option, modified to reduce lead times and utility financial exposure, also will limit utility capabilities to deal with future uncertainties. A combination of problems brought on by insufficient attention to the inherent complexity of nuclear power, high construction costs, and inefficient regulation has resulted in a loss of public confidence in that option. Resolution of these problems and changes in the technology -- primarily development of smaller, standardized reactors which emphasize inherent safety features -- will be necessary if this option is once again to be one of the choices available to utilities.

While it is not likely that most utilities will face severe capacity limitations for the rest of the 1980s, the uncertainty that does exist, particularly in the 1990s, makes it quite important that utilities move in the direction of enhancing their planning capability and flexibility, and that a wide range of demand management and electricity supply choices are available to the nation's electric utilities.


(Giga watts surplus or shortfall)
25
20
15
10
5
0
-5
-10
-15
-20
U.S. peak demand growth^b
1.5% (U.S.: 93 GW surplus)
2.5% (U.S.: 39 GW surplus)
3.5% (U.S.: 14 GW shortfall)
4.5% (U.S.: 68 GW shortfall)
ECAR 2.4
ERCOT 4.0
MAAC 1.3
MAIN 1.8
MAPP 2.4
NPCC 1.7
SERC 2.9
SPP 2.7
WSCC 2.6
NERC region^c

The **Chairman**. Thank you very much.

Dr. Merklein, on page 12 of your statement, you indicate that cogeneration and small power projects could add as much as 5 percent to capacity, according to some studies. You carefully don't state whether that's your conclusion or not.

But 5 percent of the capacity required by your figures in 1995 would amount to 40 gigawatts. Your shortfall is projected to be 10 gigawatts. If that is correct, even one-quarter of the cogeneration and small projects forecast by others would wipe out the deficit. Is that not correct?

Dr. **Merklein**. Mr. Chairman, I'd like to have Mr. Eynon address that question. I do want to say this, though; we are about to field a study on cogeneration as part of the MECS, the Manufacturing Energy Consumption Survey. So we will be dealing directly with that question.

Mr. **Eynon**. Senator, you are correct that the 5 percent of cogeneration capacity by the year 2000 is an estimate of others. They are not EIA projections. In fact, if the cogeneration capacity is available, it would reduce the uncertainty associated with needed capacity. We do indicate a range of 3 to 24 gigawatts that would be needed over and above what utilities are currently planning by 1995.

The **Chairman**. I was just referring to the table attached to your testimony which was placed on the chart. I think 800 gigawatts is near the mid-range of your projected total demand in 1995. And according to table 2, in the mid-case GNP growth, you would have a projected shortfall of 10 gigawatts. That's where I was getting the information.

Now, if the cogeneration and small projects amounted to one-quarter of the 5 percent that some are estimating, then that would exactly equal the shortfall.

I guess that's an uncertainty, but I wanted to make certain that I was not misreading either your statistics or your testimony.

Mr. **Eynon**. That's correct, Senator. We have not explicitly accounted for cogeneration in our forecast. To the extent that it will be there it would reduce the uncertainty associated with those forecasts.

The **Chairman**. Have you included in your forecasts conservation?

Mr. **Eynon**. In the analysis that we performed of how demand will grow in the future, the price signals that consumers have seen with regard to higher energy prices are embedded in those projections.

The **Chairman**. That's just the pricing response.

Mr. **Eynon**. That's correct.

The **Chairman**. And now, is that conservation based upon recent statistics and extrapolated to the future, or is it different than recent experience?

Mr. **Eynon**. Our projections are based on historical responses by consumers to the extent that we have the most recent data available.

The **Chairman**. Do you anticipate that the conservation in the future will parallel the conservation of the last several years?

Dr. **Merklein**. Senator, it is my understanding that we have looked at conservation and have not been able to pickup a detectable magnitude, and so, as Mr. Eynon said, it's simply a price reflection today. We just cannot isolate it as a variable and deal with it separately.

The **Chairman**. So you've simply extrapolated most recent experience?

Dr. **Merklein**. That is correct.

[Subsequent to the hearing the committee received the following:]

As stated in the testimony, the Energy Information Administration (EIA) assumed no retirements of existing plants in its projections of generating capacity for 1995. Utilities reported to EIA that they expect to retire 19 gigawatts of capacity between now and 1995. Most of this capacity is oil and gas steam, which EIA projects will be used to meet intermediate and peak demand and thus operates at very low utilization levels. If the 19 gigawatts of capacity are in fact retired, this is not likely to increase the shortfall. Based on EIA's representation of utility load patterns, the shortfall is expected to include both baseload coal plants and peaking turbines. Since most of the capacity scheduled for retirement is projected to operate at low utilization levels and is located in regions where available capacity is more than adequate, no significant impacts of these retirements are likely. In addition, other units already on line or expected to be on line could be used at higher utilization rates to compensate for retired units.

Capacity additions in EIA's base case forecast are based on the most recent plans by electric utility companies as reported to the Energy Information Administration. At the time the forecast was made (mid-1984), 119 gigawatts were reported as coming on line by 1995. No delays or cancellations of these coal-fired and nuclear generating plants were assumed in the base case. In order to determine the potential impacts of construction delays, EIA performed an additional sensitivity analysis where 12 gigawatts of nuclear plants and 5 gigawatts of coal plants, currently announced or under construction, were assumed cancelled or delayed beyond 1995. Nuclear plants that were 1) less than 40 percent complete, 2) experiencing severe financial difficulties, or 3) with no construction activity were assumed cancelled or delayed. Coal plants, where boiler shipments had been postponed indefinitely, were also omitted from 1995 capacity additions. Under these assumptions for construction delays, the capacity cushion is projected to be reduced further. These assumptions coupled with a 2 percent annual growth rate for the economy (low eonomic growth case) indicate that reliability problems are likely to occur in the Western United States and New England by 1995. Under high economic growth conditions (3.4 percent annual growth rate in GNP), and assuming that 17 gigawatts are delayed and/or cancelled, all regions of the United States, except for New York/New Jersey and the North Central region, are projected to experience capacity shortfalls by 1995. In addition, 1995 utility consumption of oil and gas is projected to increase by about 300 thousand barrels per day of oil equivalent. Higher fuel costs due to increased use of oil and gas could result in electricity price increases of about 0.3 percent in real terms above current levels in the high economic growth case.

Due to the uncertainty associated with forecasting cogenerated power and the lack of available data in this area, EIA has not included cogenerated power in its projections. Cogenerated electricity could ease the requirements for new capacity needed by 1995 if it is located in regions where additional supplies could offset needs for central station power plants. However, as stated in the testimony, the estimated capacity shortfall by the year 2000 is estimated to range between 38 and 145 gigawatts depending on the economic growth conditions assumed. If estimates of cogenerated power of 5 percent by the turn of the century prove to be correct, the shortfall would be offset only under low economic growth conditions, and then only if cogeneration capacity were situated in regions where the shortfall is likely to occur. It is unlikely that these cogenerated units would be situated optimally given the high variability of State incentives for cogenerated power.

EIA projects electricity prices will fall slightly in real terms between 1985 and 1995. This projection is based on expected costs to generate electricity, including fuel costs, operations and maintenance (O&M) costs, and capital charges. Because utilities are completing current construction programs, the capital charge component is projected to decrease between 1985 and 1995. Even though the other components (fuel and O&M) are projected to escalate, these increases are projected to be less than the projected drop in the capital charge component of prices. Therefore, average electricity prices will decline slightly in real terms. This trend would be reversed if utilities initiate construction programs beyond those currently under way or if costs to complete current construction exceed those assumed. These projections of declining prices are supported by recent data. EIA estimates that real prices for electricity declined by about 0.2 percent in 1984 and by over one percent in 1983.

Table 2

U.S. Generating Capacity, Projections for 1995 (Gigawatts)

	Low GNP Growth	Midcase GNP Growth	High GNP Growth
1995 Requirements	785	792	806
Existing	672	672	672
Inactive	–9	–9	–9
Operable	663 (a)	663 (a)	663 (a)
Retirements	0 (*)	0 (*)	0 (*)
Planned Additions	119 (b)	119 (b)	119 (b)
1995 Planned Capacity	782	782	782
Projected Shortfall	3	10	24

	(a) Existing Operable Capacity by Fuel Type	(b) Planned Capacity by Fuel Type
Coal	296	60
Oil & Gas	163	0
Nuclear	69	49
Hydroelectric / Other	84	8
Turbines	51	2
Total	663	119

*Utilities have reported 19 gigawatts of planned retirements by 1995. They were not incorporated in the forecasts. See companion discussion.

The CHAIRMAN. There are many who assume—maybe this is not correct—that easiest conservation has already been achieved, and that therefore the recent experience would overstate the conservation that might be achieved in the future. Others argue exactly the opposite: We're only just beginning to see what might happen in conservation; that price and other policy considerations have forced people to look at conservation, study its possibilities, develop its technologies, project its economics, but that the real impact of that past action is yet to be felt in actual conservation practices.

Which view do you hold?

Dr. MERKLEIN. Senator, we have within the Department of Energy—not EIA—a conservation study that is published every year. We seem to have indications that conservation has had some impact, but again we cannot isolate it. And at EIA we have not perhaps dealt efficiently with it, and I would not venture an opinion on it unless I could back it up with statistical data.

The CHAIRMAN. Dr. Bodde, do you have an opinion about whether conservation has had its big bulge, or is about to take off?

Dr. BODDE. I think, sir, a lot of the question of conservation comes from the price incentives for it. To the extent that the cost of electricity is reflected in its price that the users see, then certainly there are the economic incentives to pursue this. I suspect that without those incentives, it would not be pursued vigorously.

The CHAIRMAN. Do you assume that we will have the same degree of price escalation over the next 10 years that we have experienced in the last 10 years?

Dr. BODDE. No, sir, I don't. In my view, prices will moderate. We have seen interest rates fall from the high levels of the last few years. We have seen fossil fuel prices fall. There are prospects for both to continue. The question is, does that offset the higher capital cost of facilities that are now in prospect for coming on line?

The CHAIRMAN. We have a number of plants in process, and unless CWIP has been applied, the price impact of those projects is not yet reflected in rates.

Dr. BODDE. Yes, that is correct.

The CHAIRMAN. And second, I would assume then that if you believe that the price increase over the next 10 years is likely to be more moderate than the price increase in the last 10 years, and you believe that conservation is related to price increase, then do you conclude that conservation is likely to be lower over the next 10 years than it has been in the last 10 years?

Dr. BODDE. Yes, that would follow. I would like to say, though, that I think it's a very region-specific sort of thing. The price shocks that we are talking about from these large facilities are in limited regions, and the effects in these regions would be markedly different from those felt in regions that generate largely with fossil fuels.

The CHAIRMAN. Now, conservation that's price-related has several different components. One is the shifting to other processes that are less energy-intensive, just use less energy. Others, such as a consumer in the household determining that they will set the thermostat up instead of using air-conditioning quite so much, or that they will heat less in the winter rather than consume as much electricity for heat as they have—other conservation is shifting from electricity to an alternative energy. Other conservation is shifting the process away from energy toward some other component of production cost in lieu of the consumption of energy.

It's hard to sort out all those variables.

Dr. **Bodde**. Yes, it certainly is. The general shift in the economy away from a goods economy and toward a service economy has certainly been a factor in the first type of conservation that you mentioned.

The **Chairman**. Dr. Rowberg, do you anticipate that conservation in the future, the increase in conservation will match that of the past, or be higher or lower than that of the immediate past?

Dr. **Rowberg**. I think that the growth rate of conservation in the future will be much slower than in the past, and I think you are correct in saying that most of the easy things have been taken. What we will see are the effects of a substantial number of investments made during the last 10 to 15 years, continuing to work their way into the economy. We will see that new buildings and new homes are built more efficiently than homes currently on the market—or currently existing—and we will see continued investments in industry because conservation in industry is driven not so much by energy costs, but by trying to increase total productivity.

To the degree that investments are made in energy intensive industries, they will be more energy-efficient, simply as one step in increasing total economic productivity. And, incidentally, that is one factor that will contribute to electricity use. There are many opportunities that have been identified over the next two or three decades that could increase energy efficiency substantially by switching to electricity, but these things are not likely to show up for a while because of the relatively long time it takes for capital stock to turn over.

The **Chairman**. Does robotics increase or decrease energy consumption?

Dr. **Rowberg**. It should, on the total, probably decrease energy consumption. The Electric Power Research Institute in a study on robotics, indicated that the potential for introducing automatic controls in machines in manufacturing is probably on the order of 2,000 megawatts of additional capacity by the end of the century.

But in terms of increasing overall production efficiency, it would probably—quite probably lead to a net decrease in total energy use.

The **Chairman**. Would it reduce heating and air-conditioning and lighting costs dramatically .

Dr. **Rowberg**. Well, certainly it would reduce those, but by just merely increasing production efficiency, you're necessarily going to reduce energy use.

The **Chairman**. Dr. Rowberg, on page 3 of your testimony, at the bottom of the page, you're talking about major industrial uses of electricity, and you identify metal products industry, commodity chemicals, petroleum refining, pulp and paper and cement.

With perhaps one exception, aren't those the areas of our industry that are declining most rapidly?

Dr. **Rowberg**. Well, chemicals, of course, is growing. Pulp and paper is probably going to grow at least as great as the GNP, if not greater. But you're correct about the others. Cement, obviously, is not going to be an industry that will be suffering too much from international competition, but it does move quite closely with the building industry which is subject to a substantial amount of uncertainty.

The CHAIRMAN. Washington Water Power Co., in the State of Washington service area, which includes northern Idaho, recently announced plans to cancel construction of a coal-fired generating plant. One of the reasons cited was declining forecasts of future energy consumption.

I think that has to be related also to the fact that the largest single customer on their service system was a smelter in the northern Idaho Panhandle that has closed down for environmental and economic reasons. And the mine output, which has also declined because of the general decline of the metals industry worldwide and, more pointedly, in the United States, the mine output no longer flows through a smelter served by Washington Water Power or indeed any other U.S. utility. Those concentrates are shipped to Belgium for refining.

That pattern is a growing pattern, is it not?

Dr. ROWBERG. Yes. With those industries, for those regions, it certainly is. It's a shift due to many factors, as you pointed out. But the net result is a decline or certainly a very slow growth in the requirements of electricity for industries that are fairly electric-intensive, as the smelting industry is.

The CHAIRMAN. Dr. Merklein, I carefully examined your full statement. And as I look at the projections, I believe you have not considered any retirements of current plant capacity. Am I correct?

Dr. MERKLEIN. That is correct. Yes.

The Chairman. Have you assumed that there will be no cancellation of any of the planned or underconstruction plants?

Dr. MERKLEIN. We assumed and stated explicitly the assumption that all plants now under construction will be completed.

The CHAIRMAN. And you have assumed no delays in the construction schedules of those plants?

Dr. MERKLEIN. That is correct.

The CHAIRMAN. Now, if we look at the fact that much of the plant capacity by 1995 will be in excess of 35 years old, is it realistic to assume that in every instance we'll be able to extend their life for measureable periods?

Dr. MERKLEIN. That may not be, Mr. Chairman. We just stated our assumptions and ran with them. And, having stated the assumptions, of course, the user is free to make adjustments. We showed some of these adjustments that might be reasonable; for example, on retirements, we said between 40 and 60 gigawatts is a reasonable proposition between now and the year 2000.

Also, having stated the assumption, the user might make his own deduction in terms of those plants that might not be completed.

The CHAIRMAN. I don't mean to be critical, but there's a danger in constructing your statement in that way because people look at the end result of your conclusion, and your conclusion is a projected shortfall in midcase GNP growth of 10—10 gigawatts—and I suspect a good many people will look only at that chart, and they'll not read your statement.

Perish the thought that they won't hang on every word.

Dr. MERKLEIN. I suspect, Mr. Chairman, like yourself, those who have a significant role to play in any of these proceedings or in rate proceedings will probably look at the whole statement. And we are rather very explicit as to what the assumptions are.

The CHAIRMAN. I think the planners for utilities will, but the people who write articles for newspapers won't.

Dr. MERKLEIN. We have tried for a long time to get their attention, Mr. Chairman.

The CHAIRMAN. I understand that. I'm trying now.

If I can in any way point to some of the dangers of the assumption—that's all I am trying to do, so that we do indeed get the public informed as to what the consequences might be if indeed there were some retirements of plants, if indeed there were some cancellations of some of the plants that are under construction or planned, if indeed there were any substantial delays in construction schedules.

Again, perish that thought. But if you look at the last 10 years, we have seen great delays in construction schedules. We have seen lots of cancellations of plants. More utility executives may well look at the imprudence rules and judgments being applied by utility commissions, and decide at some point in this schedule, hey, wait, the risk is too great; let's pull the plug now, or let's put it on hold for a while.

If those trends hold up at all, then I think there would be—perhaps I shouldn't use the term "measurable," but at least predictable reduction in plant capacity for 1995 which would increase midcase GNP growth shortfalls for 1995.

What assumptions did you make with respect to electricity cost over the period of your projections?

Dr. MERKLEIN. Electricity price will decline slightly nationwide.

The CHAIRMAN. It will decline. It will not follow inflation?

Dr. MERKLEIN. That is correct. And that is mostly because as plants are being completed and no new construction enters the pipeline, the whole construction load is reduced.

The CHAIRMAN. Unless there's CWIP, the plants that are under construction or planned are not yet in the rate base, and the capital costs of those is far above the average capital costs systemwide, if we just average over the country.

If that's the case, the additions, as these come on line, are going to increase utility rates, not decrease them—are they not?

Dr. MERKLEIN. I'd like to have Mr. Eynon answer that one, please.

Mr. EYNON. In fact, the capacity that will come on line, coal and nuclear capacity, is more expensive than capacity that is currently in operation.

The CHAIRMAN. Nuclear is capital-intensive and low fuel cost?

Mr. EYNON. Yes, sir. So for particular utilities who are bringing on those facilities, potential does exist for sharp price increases. However, looking at the national level, we do not find that the capacity additions are sufficient to dominate the total national picture. As a result, as we look out into the future, we find that the capital component of electricity prices is decreasing. While fuel costs and operating costs are increasing in real terms, they're not increasing sufficiently to overwhelm the reduction in the capital component.

As a result, we find that electricity prices are declining slightly in real terms. In other words, they would be increasing at a rate slightly less than inflation.

If additional capacity is required over what is forecasted and utilities to build new capacity, then this trend could be reversed and we potentially could see higher prices.

The CHAIRMAN. Excuse me. I wonder if we could have just a very brief recess. I'll be right back.

[Recess.]

The CHAIRMAN. The committee will come to order.

Dr. Bodde, on page 5 of your statement, you say that it is misleading to infer future shortages simply by comparing capacity now in place with demand under various growth scenarios.

Now, if we accept the idea that electric utilities are serious when they say they don't intend to build new baseload capacity unless there are certain regulatory policy changes, why is that misleading?

Dr. BODDE. It is misleading because new baseload capacity in the sense of the 1000 megawatt plant is not the only option for them. What they may do is build intermediate size units. There are certainly a number of technical options for that. Or if they are completely constrained on the capital side, they may build small peaking units—ones that limit their capital exposure, but that have high variable generating costs.

The CHAIRMAN. So there would be consequences on the cost side.

Dr. BODDE. Yes, sir; absolutely.

The CHAIRMAN. Even if the shortage did not occur?

Dr. BODDE. Yes.

The CHAIRMAN. Dr. Bodde, have you made any studies or comparisons as to the direct and indirect social costs of surpluses as compared to the direct or indirect social costs of shortages?

Dr. BODDE. We've not studied it in the sense of social cost. We have compared in a back-of-the-envelope sense the cost of overcapacity versus the cost of undercapacity.

The CHAIRMAN. More direct economic evaluation.

Dr. BODDE. Yes; in the former case, the cost of overcapacity is carrying charges. In the latter case, the cost of undercapacity is paying more for electricity than would be the case if efficient generation were in place.

The two are roughly equivalent in present value terms. We did a scenario in which utility planners assumed a 5 percent growth rate, but got only 2.7 percent, which is currently the industrywide forecast. We ran the opposite scenario in which planners assumed a 2.7 percent growth rate and built according to that, but actually got 5. As it turns out, the present value of the cost of each are roughly in the same ballpark.

The CHAIRMAN. When you say there are alternatives other than large baseload generating plants, you are assuming that the alternative would be the construction of other plants that could meet peaking peak load, or at least that's one of the major options.

Dr. BODDE. Yes; that would be one of the major options.

The **Chairman**. Now, that would assume that there is at least a short lead time, because even a peaking plant of that capacity and of that type requires some advance planning.

Dr. **Bodde**. Yes, sir; it does.

The **Chairman**. Have you made any comparisons about a policy that would say, let's just don't meet peak demand; let's allow the shortages to occur because that's less costly to have marginal shortage for short periods of time than it is to meet that demand.

Dr. **Bodde**. No, sir; we've not looked at that particular scenario.

The **Chairman**. There are some who urge that. And I think there are some who have that on their agenda as the solution to the problem.

Dr. **Bodde**. In effect, many load management plans are similar to that, in that they would allow people to voluntarily, or in exchange for some price, allow themselves to be terminated during peak periods.

The **Chairman**. In your judgment, will there be shortages of baseload capacity on some utility systems by the early 1990's?

Dr. **Bodde**. Sir, we've not looked at that particular question. There certainly could be.

The **Chairman**. Dr. Rowberg, you have forecast demand growth in the range of 1½ to 4 percent per year. Even if electric utilities adopt your flexible planning approach, how can that degree of spread in potential demand be translated into an actual decision schedule on when to start new construction?

Dr. **Rowberg**. That particular spread couldn't. And that points out what else a particular utility would have to do, that is take steps to reduce the spread considerably for their region. We came up with that spread, given the resources we had at our disposal, as a national average. A given utility system, however, should be able to make that range much narrower by being able to look much more closely at the various technical, economic, and demographic trends that affect their service area.

Even still, they are not going to be able to come up with a single number, so that they will have to expand their options of being able to meet those uncertainties in a most flexible way.

The **Chairman**. Dr. Bodde, what happens if Congress should next week adopt a budget resolution that has in it $3 a barrel import surcharge on oil?

Dr. **Bodde**. We haven't looked at that particular question. It would certainly occur at a time when oil prices are quite soft. It would tend to put further downward pressure on oil prices by holding back demand within this country.

The **Chairman**. And it would increase the cost of electricity generation for those plants that depend upon imported oil?

Dr. **Bodde**. Yes, sir.

The **Chairman**. And that would then decrease future demand?

Dr. **Bodde**. Yes.

The **Chairman**. If people believe it will stay on.

Dr. **Bodde**. Yes, that's right.

The **Chairman**. What would happen if the aluminum industry decided that they no longer could stay in the United States, and moved offshore?

Dr. **Bodde**. Then we would certainly lose a large and valuable industry.

The **Chairman**. Well, we would also have much greater excess capacity, would we not?

Dr. **Bodde**. Yes, sir.

The **Chairman**. And that would drive costs up, spread fixed costs over a smaller base?

Dr. **Bodde**. No, because in the case of the aluminum plants, I believe they are located in an area where the generation is already embodied in the rate base and already depreciated.

The **Chairman**. But if the fixed cost is a high percentage of the total cost, and the fixed cost has to be spread over fewer ratepayers, the fixed cost will go up, will it not—the fixed operating cost?

Dr. **Bodde**. Yes, the fixed component of cost would go up. When a large generating station is dropped in the rate base, prices rise. Initially there is little demand response. In the long run, however, there may be a 1-for-1 percentage decrease in demand for an increase in price—holding regional income constant. Electricity price increases eventually affect the growth of electricity demand.

The **Chairman**. What happens to our projections if the country adopts a policy that says we're not going to lose that industry; we're going to keep it onshore, regardless of cost.

Dr. **Bodde**. Certainly, the demand on electricity would continue for that industry.

The **Chairman**. Have you in your forecast reflected any loss of such industry?

Dr. **Bodde**. No, sir, we have not.

The **Chairman**. So you have in the forecast a continuation of those industries in that industrial load.

Dr. **Bodde**. We have not really done a forecast of electrical demands. We have simply looked at the range of forecasts of about 1½ to 4 percent and then asked the question, what does that mean for risk and uncertainty in the electric utility business?

The **Chairman**. Bonneville Power Administration made a forecast of the rate impact if the aluminum industry moved out of the Northwest. And the rate impact in the Northwest would be horrendous because it has a cascading effect. First you dump fixed cost on the remaining consumers. That fixed cost in itself causes reduced consumption which increases the rates on the remaining consumers.

And they're looking at something like a 40-percent rate increase if the aluminum industry moved out. I think Senator Evans and the Northwest Power Planning Council arrived at similar, if not identical, conclusions. That, I guess, merely complicates the problem of forecasting.

Dr. **Bodde**. It does indeed. It also begs the question of whether that power might be used to provide economic generation elsewhere and whether improving the transmission system might be an appropriate economic avenue.

The **Chairman**. We have such surpluses now, we can't market them all, and BC—British Columbia is chomping at the bit to come in with their surpluses. The people in southern California salivate over the prospect.

Dr. **Bodde**. Yes, I'm sure.

The **CHAIRMAN**. Dr. Bodde, one final question. Do you have an opinion on how you define or separate, if indeed you can, or make a distinction between imprudence and mismanagement?

Dr. **BODDE**. No, sir. I cannot imagine how that could be done. I think that's more of a legal question than an economic question.

The **CHAIRMAN**. Well, I wish it were a legal question, but I'm afraid it's a political one.

Dr. **BODDE**. Yes, sir.

The **CHAIRMAN**. Thank you, gentlemen, very much. There may be some additional questions to be submitted for a response in writing. And I appreciate the very great care and attention you've given to preparing these statements. It's obvious from the quality of the statements that you took the assignment seriously and the statements are of uniformly high quality.

I appreciate very much the effort that you went to to help us out on what is a very tough problem for us. Thank you very much.

We'll next hear from a panel, Mr. Larry Hobart, American Public Power Association, and Bob Bergland, NRECA.

It will be our intention following the appearance of that panel to recess for lunch.

It is a particular pleasure to have Mr. Bergland back before this committe in a different capacity than he has several times in the past appeared.

Gentlemen, your prepared statements will be placed in the record in full. And I would invite you to summarize those statements as briefly as you can.

Mr. Hobart.

STATEMENT OF LARRY HOBART, DEPUTY EXECUTIVE DIRECTOR, AMERICAN PUBLIC POWER ASSOCIATION

Mr. **HOBART**. Thank you, Mr. Chairman.

Much of the material contained in my formal statement has been dealt with by other witnesses and I don't intend to repeat the statistics.

In the main, our analysis of the first question, whether there will be serious shortages of electricity in the early 1990's, is that that is unlikely. And most of the reasons that we believe that is a correct answer to the question have already been described by prior witnesses and are covered in my prepared statement.

I think it's useful to emphasize again—and you've done this repeatedly in your own questions, Mr. Chairman—that there are a large number of uncontrollable variables that none of us can quantify and we have to simply live with them and hope that we can satisfactorily discern in the short run how they're going to impact our situation.

They clearly include the rate of economic expansion, the degree of energy conservation which we can anticipate over the next decade, the amount of cogeneration that might be initiated, and, perhaps as important as any of those, the nature of competition between fuels and electricity.

You have taken testimony from the Gas Research Institute and I think that testimony, while it was very useful in a general way, did not emphasize how seriously the gas industry believes it can compete with electricity over the next 10 years, particularly in the home heating markets, where gas already supplies about 50 percent of all home heating, and in process industries.

The gas industry is also starting to proof-test 40 kilowatt-size fuel cells in commercial establishments, and if it should turn out that these machines are economically and technically viable, it would not be a great surprise to find gas companies becoming even more combination companies than they might have been previously, by maximizing use and servicing of fuel cells.

Your second question: What would happen if shortages do occur? None of us can predict with exactitude whether they will or will not. And again, I think prior witnesses have emphasized most choices that are available to electric utilities. They would include, of course, increasing the efficiency of existing plant, which is a distinct possibility and is already on the timetable for most utilities with generation. They would include expanding efforts to cause consumers to conserve. And I would point out that in my prepared statement, we have given several examples of how that might be done by using price signals which would give you a fairly short-term opportunity to decrease peak and, in some cases, actually decrease the growth in energy use.

Combustion turbines have been discussed, of course, as have purchases from other utilities, including the sort of wild card in the whole mix, imports from Canada, where a great quantity of electricty is available and where Canadians have indicated a keen desire to "prebuild" hydroelectric plants in order to put additional electricity into the United States.

For the small utilities that we represent, diesel engines remain a source of generation. They are very easily slapped into place, and the lead time could be even measured in weeks.

I would emphasize two possibilities that have not been discussed at great length here this morning. One is the possibility of putting in small or medium-sized coal plants in the 10-year period that we're discussing here today. As my statement indicates, it is possible to do this with relatively short lead times. Some examples I cite take that lead time down to as little as 32 months for a small coal-fired plant, slightly under 100 megawatts.

These are real examples and we think that they can be duplicated during the next years if that is necessary or economically and technically desirable.

And, last, I would refer again to the fuel cell which remains a possibility—not yet a reality, but a machine that could come into place and could make a significant difference in how we handle all of our planning in the electric utility arena.

Coal plant operations, I think, are important because we know that regulatory processes serve as a strangulating procedure in terms of implementing utility decisions, and we have a large number of coal plants that have been delayed and canceled in recent years, and even in recent months, as you alluded to a minute ago.

The fact is that those sites are frequently still available and often the particular unit that is canceled is part of a larger package of units on a single site. Hence, the opportunity to expand quickly might well be available when we can utilize the existing auxiliary facilities and the location itself.

Your third question asks what are our views on the retirement of generating plant. I think again, to emphasize the statements of prior witnesses, there is a definite opportunity to refurbish existing plants and the utilities are in the process of investigating or actually implementing exactly those solutions currently.

The costs of refurbishing in many cases are not great. And not only is the plant given additional life, but it is entirely possible that you can upgrade the facility and get out of it some 5 to 10 percent more than you would otherwise. I've given some figures as to what those costs might be in carrying out such a refurbishing.

Your questions that relate to minimization of investment on the part of utilities tend to focus, I think, on the activites of privately owned electric companies. And as you are well aware, Mr. Chairman, the process for securing approval for financing on the part of a public agency that's in the electric business is somewhat different. In only a few instances are the financing capabilities and authorities required to be reviewed by State agencies. And the local community is frequently the entity that decides whether the investment should take place or not.

The driving force in all of these investment decisions, of course, is what energy services are going to be required in the community. Again the uncertainty of load growth affects the willingness to make these decisions, but they are still being made. We believe that they can continue to be made because the groundwork that is done to indicate the need justifies the action, and subsequent review is not required in most instances.

But there is also the overriding fact that all witnesses, I think, have referred to: Nobody knows for sure what is going to happen to load growth. What this means for utilities generally is that flexibility in planning and implementation of decisions becomes the order of the day, and the whole spectrum of possbilities running from energy conservation through cogeneration, up to the construction of major or minor generating stations is going to be examined to determine its feasibility in both the technical and economic way.

Rate suppression is not the same issue as it relates to public agencies as it might be with private companies. You have been asking witnesses for a definition of what is mismangement and what is imprudency. In the public power arena, imprudency is when people criticze your mistake; mismanagement is when they fire the manager and turn over the boards of the PUD's in the State of Washington.

All of these decisions are going to involve planning on the part of utilities, but they're also going to involve planning on the part of the public because there is clearly not a consensus throughout the body politic as to what the correct decisions are. And without such a consensus, or at least a modicum of it, we can't implement decisions or, if we do, it's only done with significant cost penalties which are going to be ultimately imposed on consumers.

At the conclusion of my statement, I have suggested a formulation of your last question which might be, we believe, more appropriate. I've also posed for you an eighth question which is the subject of some future hearing perhaps: How could we do the optimum thing, and how could we eliminate some of the regulatory problems that we've currently got by streamling and focusing our decision-making?

[The prepared statement of Mr. Hobart follows:]

AMERICAN PUBLIC POWER ASSOCIATION
2301 M STREET NW WASHINGTON DC 20037 • 202/775-8300

Statement on
"WHEN WILL THE LIGHTS GO OUT?"
Submitted to the
SENATE COMMITTEE ON ENERGY AND NATURAL RESOURCES
by
Larry Hobart, Deputy Executive Director
AMERICAN PUBLIC POWER ASSOCIATION

July 25, 1985

My name is Larry Hobart. I am Deputy Executive Director of the American Public Power Association. APPA is the national,service organization which represents 1,750 local publicly owned power systems, mainly municipal electric utilities, located throughout the United States.

Public power systems have special characteristics which affect their consideration of bulk power supply questions. Here are some of their distinguishing features:

- Public power systems vary greatly in size measured by customers served. The smallest such utility is the Electric Department in Tennant, Iowa, which has 25 customers. The largest system is the Department of Water and Power in Los Angeles, which has 1,238,752 customers. The average public power community has less than 6,000 customers; eliminate the 20 largest public power systems in the U.S., and the average size drops to less than 3,300.
- Despite their generally small size, many public power systems are in effect vertically integrated operations, dealing directly in generation, transmission, and distribution functions. This is true not

merely because about one-quarter of all publicly owned electric utilities produce and/or move power with facilities which they own and operate, but also because roughly one-half of the nation's public power systems are involved with "joint action agencies" -- entities created to act on behalf of a number of individual community-controlled electric systems for the purpose of providing a common bulk power supply. Fifty-seven of these organizations exist in 31 states. Approximately one-half of the joint action agencies currently operate powerplants or own part of a plant operated by another utility. Others act as an agent for their members in purchasing blocks of power on the open market.

- Some 900 public power systems buy all or part of their power from private power companies whose wholesale rates are subject to the regulatory review of the Federal Energy Regulatory Commission. About 550 publicly owned electric utilities purchase power from federal power marketing agencies, and another group acquires power supply from state agencies or generation and transmission cooperatives. All of these buyers of power are affected by their suppliers' problems in terms of the cost and availability of electricity.
- Public power systems are nonprofit institutions which belong to the citizens of communities which they serve; the users and the owners are one and the same, and all of the economic benefits are retained locally. Public power systems are service-oriented and have no built-in economic bias toward a particular technique or technology. Thier goal is simply to provide what the consumer wants -- energy service at the lowest possible cost. Major plant expansion by public

agencies is normally financed by issuing tax-exempt municipal bonds. The electorate of the community plays a representative role in directing activities of public power systems through selection of city councils and governing boards, and by public participation in the formulation of policies and programs which shape utility projects. Municipal electric utilities are part of a city government just like water supply, sewage disposal systems, garbage collection, and human services. They all share general community objectives. Because of this fact, there exists a unique opportunity to integrate city services in a fashion which simultaneously enhances the operation of the utility and other functions. Cities and towns with municipal electric utilities are both distributors and users of electricity. They have a clear and unconstrained interest in the cost-effective delivery of this service for street lighting, water pumping, sewage treatment, and building heat, cooling, and illumination. Just as homes, businesses, and industries seek the lowest cost electricity, local government wants to keep its electric bills down, too.

These different facets of public power -- nonuniform size, multiple power sources, and community orientation -- are all significant factors in assessing the potential for shortages of baseload generating capacity in the early 1990s.

APPA offers the following answers to the seven questions posed by the committee staff in its memorandum of July 16:

1. **Will serious shortages of baseload generating capacity occur on individual utility systems by the early 1990's?**

Although no prediction can be credited with certainty, anecdotal and aggregate analyses presently available indicate that serious shortages are unlikely during the next 10 years, based on utility projections of load growth.

"The projected growth rates of electric energy requirements and winter peak demand for the contiguous United States, for the period 1985-1994, are fractionally less than projected a year earlier for the period 1984-1993," the U.S. Department of Energy reported in its May, 1985, staff report, "Electric Power Supply and Demand for the Contiguous United States 1985-1994". "The projected growth rate of summer peak demand is a trifling amount more than the year-earlier projections." DOE provided the following table summarizing the projects:

	TEN-YEAR AVERAGE ANNUAL PERCENT INCREASE	
	Projected 4/1/85 for 1985-1994	Projected 4/1/84 for 1984-1993
Annual Energy Requirement	2.38	2.65
Summer Peak Demand	2.33	2.27
Winter Peak Demand	1.94	2.22
Summer Net Capability	1.65	1.77
Winter Net Capability	1.50	1.61

DOE's growth rates are composites of the growth rates projected for the nine regional reliability councils. Each council's growth rates, in turn, incorporate projections made by individual electric utilities composing that council. DOE observed that the table "reflects a general consensus among electric utilities that annual electric energy requirements and winter peak demand will grow during the next decade at a slightly smaller average annual rate than was forecast for each of these quantities a year earlier, while the summer peak demand project is practically unchanged." The Department noted that the projected annual increase in generating capacity for the period 1985-1994 is less than that projected a year earlier for the period 1984-1993, but nevertheless declared that: "Bulk power supply in general, for the period

1985-1994, is projected to be adequate for meeting projected peak demands. While the DOE analysis indicates some potential for inadequate power supply in some electric regions, measures can be taken by the utilities affected to minimize the effect of such inadequacy."

There are a number of uncontrollable variables which will affect what actually happens to load growth. They include the rate of economic expansion, the degree of energy conservation achieved, the amount of cogeneration initiated, and the nature of competition between fuels and electricity.

Economic Expansion. Although the nature of the relationship between Gross National Product and electricity demand has changed in recent years, the link has remained statistically strong. Prior to the early 1970s, a one percent increase in GNP could be roughly expected to yield about a two percent increase in demand for electricity. Since the early 1970s, this same one percent increase in GNP accounted for only about a one percent or less increase in electricity sales. Data for 1984 show that real GNP increased by 6.8 percent over 1983, electric energy growth was 5.9 percent, and electric demand growth was 4.1 percent. For the first half of 1985, real GNP increased 2.6 percent above its 1984 level, while electric energy use was up 2.1 percent.

To the extent that electric use is driven by economic growth, contemporary national forecasts and figures do not foretell a surge in power production.

Last week, a group of five prominent private economists told a House subcommittee of the Committee on Banking, Finance, and Urban Affairs that they do not think the economy is going to drop into a recession, but neither is growth going to rebound sharply. Three of the five -- Norman Robertson of Mellon Bank, Lawrence Chimerine of Chase Econometrics, and Michael Sumichrast of the National Association of Home Builders -- suggested that the U.S. will experience a "growth recession" through 1986. A "growth recession" is defined as a situation in which real output does not fall, but it grows so slowly that idle productive capacity and unemployment increase.

About two-thirds of Gross National Product is accounted for by consumer spending. Individuals and families are affected by current economic conditions. For five consecutive months, the unemployment rate has remained at 7.3 percent as the number of workers entering the labor force has just about matched the number of new jobs created. Census Bureau data released last month show that most American families have lost purchasing power since 1980. After adjustment for inflation, after-tax income declined for two-thirds of U.S. households, including those in the lower-, middle-, and upper-middle income levels. Only the top fifth of households gained purchasing power over the period.

Energy Conservation. "The United States requirement for electric energy will no longer follow the historic growth rate observable in the past 50 years," the U.S. Department of Commerce asserted in a study titled "U.S. Energy for the Rest of the Century," dated July 2, 1985. "The historic growth rate is no longer valid since the electrification program which began after World War I is virtually completed. The new electricity growth rate will be driven by the increase in population and the desire to substitute electricity for oil and natural gas. The substitution of electricity for oil and natural gas is a function of relative costs and reliability of supply to the users. The impact of both of these factors is tempered by overall national energy conservation efforts."

Joseph F. Gustaferro, senior energy analyst in the Commerce Department's Industry Analysis Division, concludes that energy use generally will be lower than prior predictions of the Department in 1976. He asserts that: "The reduction in the forecasts of projected energy use derive from a single major source: U.S. requirements for electrical energy. This requirement is markedly reduced because of expected conservation and increased efficiency of energy use in industry. Other sources of energy in the forecast have not been changed in the seven year period except solar and electricity from wind and waste. All three of these energy sources have been decreased to more realistic values."

Gustaferro projects an annual growth rate for electricity of 2.4 percent, half of which is related to oil and gas substitution and half to population growth. He comments on rapid rise in electricity use experienced in 1984:

> There has been some concern by both analysts and electric utility planners about the recent growth in energy consumption. The Edison Electric Institute reported on June 13, 1984 that the kilowatt hour output in the continguous 48 states increased by a hefty 8.2% in the 52 weeks ending on June 9, 1984 over the corresponding period in 1982-83. If this trend were to continue, it would cause considerable change in all energy forecasts and long-range electric utility plans. A quick analysis indicates that this growth almost exactly parallels the growth in the real GNP when weather factors are considered. However, since the 1984 forecast of this series was published, the growth rate of electricity has abated and as of the end of May, 1985 the growth rate of electricity consumption is about 2.0% over last years' electricity consumption.

Price-induced conservation is a major factor in slowing electrical load growth, Gustaferro concludes, citing last year's national electric bill of about $150 billion.

The American Council for an Energy-Efficient Economy and the Energy Conservation Coalition points out in a study titled "Energy Efficient Appliances" that:

- Decisions on the approximately 32 million major domestic appliances purchased in the U.S. in 1981 had a greater cumulative impact on the nation's energy situation than any decision made about starting new coal mines, oil wells, or powerplants. For example, the annual output of over six large (1,000 MW) coal or nuclear plants was required to operate the major electrical appliances sold in 1981 alone.

- All residential equipment consumed one-third of the electricity produced in the U.S. during 1980. Refrigerators utilized the output of about 25 large powerplants, nearly seven percent of the nation's total electricity consumption and over 50 percent of the nuclear power generation.
- The cost for operating residential appliances has become a major expense. A typical household paying the average electricity price charged by private utilities (6.8 cents per kilowatthour during the first eight months of 1982) will spend over $700 a year operating a refrigerator, freezer, electric water heater, range, clothes washer and dryer, lights, and other electrical appliances. Heating and air conditioning could add another $800 or more in a typical all-electric home. Furthermore, the cost of energy for operating appliances over their useful life is a number of times their first cost.

The study notes that the energy consumption of the most efficient appliances available today is dramatically lower than that of typical models produced in recent years. "If the entire stock of appliances in the year 2005 consisted of the best models now available, residential electricity consumption would drop 37% from projects based on historical trends, equivalent to the output from more than 100 large power plants," the two organizations reported. "Why has the efficiency of some appliances improved? Industry representatives attribute it to consumer demand stemming from rising electricity prices, and manufacturers responding to that demand. However, substantial evidence points to minimum efficiency standards promulgated in California and other states, plus expectation of federal standards, as an inducement." Over half the states currently have appliance efficiency standards. On July 16, the U.S. Court of Appeals for the District of Columbia ruled that the Department of Energy erroneously interpreted existing law and must set efficiency standards for major appliances.

Public power systems are involved in a great number of programs designed to cut peaks and/or save energy, including direct control of water heater and air conditioner loads; time-of-day rates; weatherization and insulation; energy audits and report card billing; energy audits; loans; appliance and lighting rebates; passive and active solar programs; heat pump promotions; district heating; and improved street lighting.

Thermal standards in building codes, use of "smart thermostats" in homes, third party "shared savings" programs, and construction of "intelligent buildings" which manage energy use with microprocessors and variable air volume controls all have the effect of limiting growth in use of electricity.

"The electric-intensity of U.S. industry (electricity used per unit of output) has held steady since 1974," OTA reports. "This is despite a steady decrease for more than two decades in the overall use of energy per unit of industrial output. The steady relationship of electricity to industrial output is the product of two opposing trends: a steady increase in electricity use in industries which are heavy users of electricity, and a steady decrease in the proportion of output from those same industries relative to total U.S. industrial output."

Cogeneration Growth. Whatever new capacity is required to generate electricity, there are questions as to whether utilities will supply it. Cogeneration and small power producers may take a major hunk.

Since the start in 1980 of the Federal Energy Regulatory Commission's program for qualifying applicants, 1,487 facilities representing 21,429,000 kilowatts have filed. Thirty-three projects covered in filings for two sample weeks in June ran the gamut in size from 3 kilowatts up to 385 megawatts, and encompassed a great variety of "fuels," including coal, natural gas, geothermal resources, landfill gas, municipal solid waste, falling water, waste heat, and sunshine.

An abundance of fossil fuels and electricity, deregulation of natural gas, a possible further reduction in oil prices can affect utilities in three ways: competition for heating and industrial process markets may be increased as gas and oil companies seek markets; fuel costs for generating power may be decreased, improving utility ability to compete; and the market for cogeneration may be softened.

About 20,000 megawatts of cogeneration capacity will be added at sites in the U.S. between 1985 and 2000, according to a study by Frost & Sullivan -- a figure less than cited by some other experts. "Estimates of future potential have been reduced because of soft fuel and electricity prices brought about by the recent conservation efforts of both business and the private sector and the falling oil prices," the New York company stated last month. "Although the forecasts are less than were anticipated a few years ago, the potential for this market is still significant in both absolute and relative terms." As reported in BNA's Energy Report:

> About 16,000 of the 20,000 mw will be added by industrial users. By 2000, industrial users' cogeneration capacity is expected to reach 31,000 mw, according to the report.
>
> Most capacity will be installed in the chemicals industry, followed by pulp and paper and the petroleum industries. The report said that these three industries will build nearly 75 percent of the industrial cogeneration capacity and 60 percent of total cogeneration capacity over the forecast period.
>
> The Southwest, with its concentration of oil refining and chemical operations, will be the leading cogeneration region, the report said. The western states, ranked second, will be lead by California, with its diversity of industries and regulatory climate which promotes cogeneration.

Natural gas. Natural gas provides half of the country's home heating needs, is a major ingredient in industrial production, and is often the fuel of choice for cogeneration plants. Its availability at prices competitive with electricity could mean that a potential shortage of electricity would trigger a switch to gas for the purposes for which it is appropriate.

Natural gas could have another impact in the short run: commercial employment of the fuel cell to create electricity.

Gas companies are actively promoting as "alternatives to the shocking cost of electric heat" the new "pulse" gas furnace, which has a claimed "95% fuel efficiency", and are working to perfect more effective water heaters. In addition, the gas industry is currently field-testing in commercial establishments 40 kilowatt fuel cells which use gas, provide by-product space and/or water heating, and produce electricity -- a way to take the combination company right into the customer's house.

2. If such shortages occur, would each utility faced with such a shortage be able to prevent actual interruptions in service by obtaining additional supplies, such as combustion turbine generation or purchased power?

Short-term choices available to utilities would include increasing efficiency of existing plant, expanding efforts to cause consumers to conserve, purchase of power from other utilities, addition of diesel engines and combustion turbines, construction of small- or medium-size coal-fired plants, and possible adaptation of the fuel cell.

Utilities are seeking increased efficiencies to get more production out of existing equipment, including efforts to raise availability, improve heat rate, expand preventive maintenance, boost system load factor, and decrease electrical losses.

Diesel engine generating sets are a staple of small system generation. Units are readily available, and easily transported and installed. Lead-times can sometimes be measured in weeks.

Combustion turbine-generators are a tested, low-capital cost power production process with a short lead-time. Evidence of these facts is provided by plans announced this month by the Northern California Power Agency.

NCPA will break ground in August for the first of five 25,800 kilowatt combustion turbine-generating stations to be constructed at three sites at a total cost of $72 million, or less than $560 a kilowatt, with commercial operation of all five turbines expected by June, 1986. The machines will be utilized for peaking, back-up power, and service emergencies.

Cooperative ventures may aid in holding down costs of gas turbine additions. For example, the Sacramento Municipal Utility District worked with McClellan Air Force Base on construction of a 49 megawatt gas turbine powerplant scheduled to be in service this year. The plant will help meet SMUD's needs for additional capacity during peak demand periods, and will serve as an emergency power source for the base, making McClellan the nation's first energy self-sufficient Air Logistics Center.

A special solution for peaking problems is provided by improving the efficiency of air conditioning.

As pointed out in the study "Energy Efficient Appliances": "Air conditioners have an especially large peak power demand, and in fact account for a major fraction of the summer peak demand in much of the nation. Moreover, they utilize generating capacity very inefficiently, because they typically operate less than 10% of the time. The result is that although air conditioners represent a total potential demand of 30% of national generating capacity, they account for only 7% of national consumption of electric energy."

The study reports this example of how a utility can shave peak through increasing the efficiency of air conditioning: "The Springfield, Illinois municipal utility offers $25-$100 to customers purchasing room air conditioners with a SEER [Seasonal Energy Efficiency Ratio] of at least 8.5. With these relatively low rebates, the cost of saved capacity is only about $50/kW. The utility estimates that the rebate program could reduce its peak demand 15-20 MW by 1992. This would cut projected growth in peak demand approximately 20%, delaying the need for additional $1,000 per kW generating capacity."

Snohomish County Public Utility District in the State of Washington recently weatherized the 30,000th electrically heated home to participate in the utility's "Energy Buy-Back Program"; the electricity saved is estimated to equal a 15 megawatt powerplant. If all eligible electric heating customers in the PUD service area participate, the utility would produce savings equivalent to a 50 megawatt powerplant.

Capacity and energy surplus to needs of one electric utility is likely to be available to aid other utilities with deficits. Electricity supplies increased about 39 percent from 1974 to 1984 while electricity demand increased about 29 percent. Consequently, reserve margins grew from 27 percent to 34 percent over those years. For the period 1984-1994, DOE sees electricity supply growing by 1.7 percent annually, while peak demand expands at the rate of 2.3 percent a year (see attached chart); this supply-demand forecast produces a national reserve margin of 26 percent in 1994, although two regions would be below the 20 percent reserve margin requirement normally considered adequate for reliability. The following table depicts DOE's findings by reliability region:

	ACTUAL	PROJECTED		
	1984	1985	1990	1994
	(Percent Reserve Margin at Time of Summer Peak)			
ECAR	38	39	34	29
MAAC	28	29	27	26
MAIN	21	30	32	23
MAPP	39	31	22	13
NPCC	33	29	30	23
SERC	39	34	30	25
SPP	32	36	24	22
ERCOT	22	15	21	19
WSCC	39	38	38	33
U.S.	34	33	30	26

So-called "off-system" sales of electric power and energy have become a regular part of utility operations in recent years as sellers seek to recover sunk costs of excess generating capacity and buyers attempt to avoid expensive plant additions. Assuming adequate transmission services, based on DOE numbers, it appears likely that these transactions will continue and that more sophisticated exchanges of electricity will be worked out to take economic advantage of regional disparities.

Additional electricity can be imported from Canada. "Connections: An Energy Strategy for the Future," published this year by the Economic Council of Canada, reports:

> Existing and potential new sources of electric power supply are available for increased exports to the United States within the next two decades. The major possibilities include: the untapped hydraulic reserves of the Lower Churchill Falls in Labrador; tidal power in the Bay of Fundy; nuclear units in New Brunswick; current excess and additional hydraulic resources in Quebec; coal-fired and nuclear-powered generation in Ontario; the "prebuilding" of hydraulic installations in Manitoba and Alberta; and hydro facilities in British Columbia.
>
> A recent study found that there was a potential export market for Canadian electricity in the United States of between 84,000 MW and 188,000 MW by the end of the century.

There is a possibility that larger fuel cells could open up new opportunities for flexibility in electric utility operations. Fuel cells produce electricity by a chemical process. They demand little water, produce minimal environmentally noxious by-products, and may provide electric-thermal efficiencies of 80 percent with waste heat utilization. A technically and economically feasible fuel cell could be assembly-line produced in building block modules of small size, sited in a dispersed fashion to minimize transmission and land requirements, and constructed with a lead-time that is measured in months, not years.

Natural gas is the fuel of choice for the fuel cell. Its use for this purpose is not restricted by the Powerplant and Industrial Fuel Use Act of 1978. However, while the Congress repealed federal law which would have prevented utility use of natural gas in existing plant, the prohibition remains for new utility conventional generating facilities -- even though the same restriction does not apply to cogenerators. If projections of long-term surplus are valid, then the assumption of a "disappearing fuel" on which gas is precluded for use in new powerplants bears reexamination. Market forces appear to be bringing down gas prices. Gas-fired baseload generating facilities can be built more quickly than coal and nuclear powerplants, have lower construction costs, and aid national environmental protection objectives.

As OTA has pointed out, all plausible electric growth projections can be met with coal, although such a "single shot" solution would leave expansion devoid of diversity considered desirable for reliability and rates reasons, and pose potential problems of pollution control and transportation costs. On the other hand, the utility industry knows a lot about coal because it provides 55 percent of all electricity generated.

A large number of coal units were cancelled during the last decade when load growth failed to materialize as expected. Most of the sites associated with those units are still available. Preliminary planning done previously to get ready for construction can be updated without the same effort required to start a fresh project. In many cases, existing plants were planned for additional units, and the major auxiliary features are already in place. As the Platte River Power Authority, a joint action agency in Colorado, reported with respect to its 250 megawatt coal-fired Rawhide project: "The site's 500-acre cooling lake, pipelines, transmission lines, and coal-handling facilities have all been designed to accommodate additional generating units. As energy needs expand, the capacity at Rawhide can be increased to 750 MW, under existing air quality regulations."

Small- or medium-size coal-fired units do not take long to construct. Rawhide came on-line in 1984 after a 44-month construction period. Colorado Springs, Colorado, municipal utility brought a 200 megawatt coal-burning zero water discharge unit into commercial production in 1980 after five years of construction. The municipal electric system in Grand Haven, Michigan, initiated operation of a 58 megawatt coal unit in 1983 -- 32 months after start of construction.

Recent studies indicate that there are minimum financial penalties in the construction of smaller coal-fired plants, and that these added costs from loss of economies of scale may be more than offset by planning, reliability, and availability advantages. Advancing coal combustion technologies such as fluidized bed and coal gasification integrated with combined cycles lend themselves to smaller sizes.

Other fuels with practical short-term application have special interest for municipal electric systems, including garbage, methane gas from sanitary landfills, and wood waste, and are all currently utilized by public power systems to generate electricity, and use is expected to expand. Geothermal and small-scale hydro resources are also used and useful to public power systems, and come in increments which fit small systems and match load growth. Towns and cities with their own electric production facilities also look to integrated solutions to local energy problems, e.g., district heating.

Public power systems -- like all utilities -- reassess their bulk power supply situation on a rolling basis. If within a particular locale, state, or region, signs appear indicating a long-term take-off of demand for electricity, plans can be altered. While uncertainty is the driving force in utility decision-making today, flexibility is the answer.

3. In your forecast of electric power supply, what are the assumptions relating to the retirement schedule for existing generating plants?

While the "book" life of a powerplant may be considered to be 30 or 40 years, in practice thermal powerplants often operate for 50 years or more. According to a study published by the Office of Technology Assessment last year, the bulk of current generating capacity in the U.S. is comparatively new; over half has been built since 1970. "The number of plants that would be retired by 2000 varies greatly with the assumed plant life," OTA points out. "In the unlikely event that a 30-year life would be used, over 200 GW would be retired by 2000. A 50-year schedule would retire only 20 GW."

OTA also observes that 27 percent of all generating capacity in 1981 was oil and natural gas steam generating capacity. High prices of oil and natural gas could be a stimulus to retirement. However, availability for reserve duty in a time of short supply and possible reductions in fossil fuel prices might cause a decision to keep these facilities on-line.

Many public power systems with generation are looking at "plant betterment" options for improving the performance and extending the life of existing plants. Recent studies suggest that refurbishing can be carried out for costs of $200 to $400 a kilowatt and can include efficiency improvements and capacity upgrades of 5 to 10 percent. Additional incentives include the facts that siting and environmental problems may be minimized, and lead-times for doing the work shortened, compared to construction of a new plant at a new location. In light of uncertainties facing utilities, this approach is an attractive one.

In another form of "betterment," output of the nation's hydroelectric projects can also be expanded by adding turbine-generators at existing dams.

4. Do electric utilities have an incentive to minimize their investment in new central-station generating plants?

5. If so, what are the factors contributing to the incentive?

Public power systems are nonprofit service organizations directly responsible to consumer-owners to provide an adequate, reliable, efficient, and reasonably priced supply of electricity needed by their community. While municipal electric utilities make cash contributions to the operation of local government, they do not earn a designated rate of return on ratebase for the purpose of generating dividend payments. Their decision to finance a central-station generating plant is dictated by their assessment of whether such a power facility is the best choice to provide community energy requirements when judged against a spectrum of alternatives ranging from demand-side management through purchase from others up to construction of a plant.

Public power systems can currently finance new facilities. Electric revenue bond issues by public agencies are well accepted in the bond market, rating services give them generally high marks, and interest rates have dropped from an average high of about 12 percent in the second quarter of 1984 to under 9.75 percent in the second quarter of 1985.

Any incentive public power systems may have to "minimize" investment is stimulated by individual system judgments about load growth and the best way to satisfy it at the lowest possible cost. These decisions are made by city councils and governing boards on behalf of the community, citizens of which in turn will retire much of the associated debt through retail electric bills. Faced with uncertainty about future demand, public power systems seek to hedge their bets, spread risks, share large projects with other utilities, pace expansion as close as feasible to load growth, and seek flexibility through a diversity of options.

Public power system financing is also governed by the nation's tax laws. The President's tax change proposals presently pending in Congress would make changes which would adversely affect the flexibility of present utility practices and unreasonably boost costs to consumers. Attached to this statement is a memo explaining this problem.

6. To what extent have so-called "rate suppression" decisions by some state public utility commissions increased the risk of future shortages of electric generating capacity?

Only a handful of states regulate the rates of municipal electric utilities because they are community owned and locally controlled and in the main self-regulated.

7. Who should have the responsibility for electric power supply planning, electric utilities or state regulatory commissions?

A report by the Congressional Research Service of the Library of Congress dramatizes the uncertainty facing utility planners by noting that various organizations forecast a spread between low and high U.S. demands for electricity by 1995 of 64 percent -- an amount equivalent to about 320 1,000 megawatt powerplants. The cost of this difference, measured by DOE projected costs of coal-fired capacity in commercial operation in 1992, is in excess of $680 billion.

With such sums at stake, certainly consumers have an interest in ensuring that the best thinking is applied to addressing issues facing utilities and that appropriate public input is made.

However, it is not clear that the limited choice posed by the question allows a statement of the appropriate answers. A different formulation might be:

1. Utility practices tend to ignore state lines, power pools do not follow political boundaries, and regional power supply solutions predominate.
2. With current technology, regional power supply planning to assure the most effective, efficient, and environmentally benign solutions offers the best hope of coordinating decision-making.
3. How can regional planning be enhanced to ensure appropriate public and utility participation; to provide timely, cost-effective, enforceable decisions; and to define clearly the relative responsibilities of all the players?

There are, of course, many facets to this question. But one of the key ones right now is transmission -- the key to control of electricity in the United States.

The electric utility industry now has large amounts of surplus generating capacity. This surplus is unevenly distributed throughout the country. To make good use of generating capacity surpluses, willing buyers and sellers must have ready access to each other so that the most efficient units can be operated at their optimum dispatchable levels. The barriers which prevent using transmission for efficient dispatch take two forms: institutional obstacles and capacity limitations. Some utilities have denied equitable access to other utilities, even though such action was economically and technically feasible, for anticompetitive reasons. In other instances, utilities have failed to plan, size, and locate new transmission facilities in a manner which would take into account the reasonably foreseeable needs of all utilities in the affected areas.

The longstanding economies of scale in transmission have become more apparent in an altered economic environment for utilities. Voltage can be doubled for less than a doubling of cost, and doubling voltage quadruples carrying capacity. Lead-times for transmission are often shorter than for generation. A transmission line may allow a utility to tap a new generating which is less expensive than local production.

Unfettered freedom on the part of individual utilities to use -- or not use -- transmission as they see fit can conflict with societal aims:

- Maintenance of a reliable, economic, efficient, and adequate power supply in all areas of the country;
- Preservation of diversity in our pluralistic electric utility industry;

- Protection of the environment through control of land use, recognition of aesthetic values, and guarding of public health and safety.

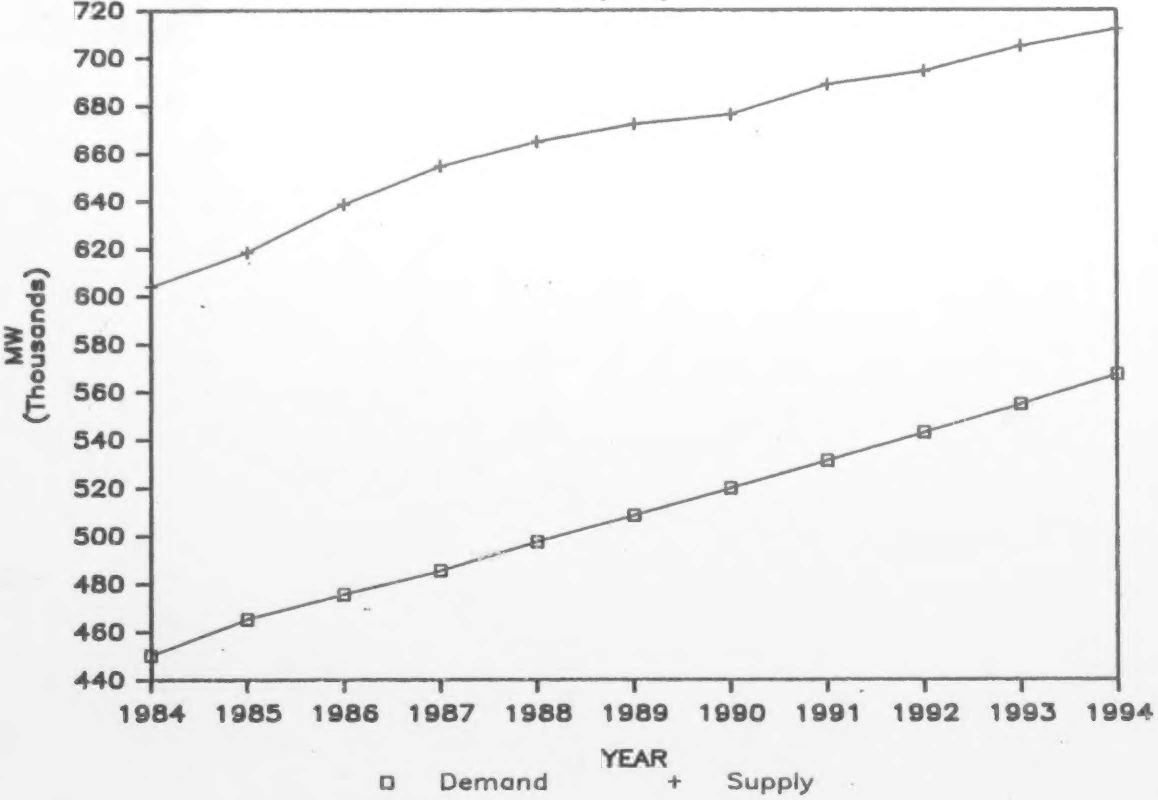
There is a failure to recognize the great value of existing rights-of-way as a public resource -- a part of the nation's infrastructure which can be expanded to carry more electricity without dedication of new land to utility corridors and with significant economic advantages to consumers. Where economically and technically feasible, and with appropriate compensation to owners, transmission should be employed to aid the public interest in an adequate and fairly priced source of electricity.

Attached to this statement is a memorandum which details some transmission problems and possibilities for dealing with them.

Because of the specific timeframe and subject limits set for the hearing, this statement does not deal with a host of details associated today with utility decision-making, including regulatory review of powerplant and transmission siting, establishment and enforcement of environmental protection requirements, administrative pricing in coal transport, the future of nuclear power, and application of new technologies. That does not mean these issues are not important. They are.

An eighth question, not asked at this hearing because it was regarded as too broad and complex for adequate coverage, is one deserving of future consideration:

8. What could be done under optimal conditions and new regulatory policies?



Total U.S. Projected Supply and Demand

(DOE)

AMERICAN PUBLIC POWER ASSOCIATION
2301 M STREET NW WASHINGTON DC 20037 • 202/775-8300

July, 1985

WHY THE PRESIDENT'S TAX PROPOSALS ARE HARMFUL TO PUBLIC POWER CONSUMERS

Municipal and other local publicly owned electric utilities are traditional public purpose issuers of tax exempt bonds. Community owned electric utility systems date back to the inception of central station electric service in the early 1880's, and many public power projects predate school, water and sewage service in their localities.

The President's May, 1985 tax proposals would impose severe restrictions on the issuance of tax-exempt bonds by State and local governments. While nominally aimed at abuses of nongovernmental use of tax-exempt financing, the proposals are so indiscriminate that they represent a serious threat to all traditional government financing, including public power, and would make such financing more costly.

There are five specific provisions of the President's tax proposals that particularly concern us:

One-Percent Rule

Under the proposed "one-percent rule" the interest on obligations issued by a State or local government would be taxable if more than one percent of the proceeds were used directly or indirectly by any person other than a State or local government. Generally, use of a facility financed with the proceeds of tax-exempt obligations would be considered to be use of the proceeds.

The ability of a publicly owned utility to sell some of the output of a plant during its early years of operation allows the utility to provide for expected growth of its own needs in an efficient manner. Selling excess capacity that is available during the early years of operation of a new facility allows utilities to take advantage of the economies of scale inherent in electric generation and maximize the efficient use of the nation's electric energy system.

This prevents resources from remaining idle and lowers the cost of electric power to all consumers. The one-percent limit would virtually eliminate this practice for publicly owned electric systems.

Examples of economically desirable arrangements that could be curtailed include long-term sales of capacity to investor owned utilities and industrial customers, and sell-backs of power and energy by publicly owned utilities when they purchase an ownership interest in a generating plant from a private party.

The proposed one-percent limit is arbitrary and ignores the basic economic and technical realities of providing electric energy from publicly owned facilities. It would reduce the viability of publicly owned utility operations, thereby reduce competition in the industry, and foster the distorting effects of monopoly power.

Prohibition on Long-Term Management Contracts

This proposal would not allow use of tax-exempt financing for facilities managed under contract by a nongovernment person for more than one year. A contract entered into by a municipal, or other publicly owned utility, with an investor-owned utility or other private party for a term in excess of a year, and which provides for the operation of jointly owned utility plant by the private party, would disqualify the investment made to purchase that plant with tax-exempt financing, even though these arrangements in no way transfer the benefit of tax-exempt financing to the private manager.

This proposed prohibition would severely hamper the joint ownership of electric facilities, and increase costs to electric consumers.

Restriction on Arbitrage

Under current law, publicly owned utilities are permitted to take advantage of arbitrage opportunities under specific, limited conditions. The revenues provided by arbitrage are used to reduce the costs of constructing energy facilities and thereby lower electric rates to consumers.

The President's proposal would increase the financing costs of publicly-owned power suppliers by restricting their ability to earn arbitrage. It would require the rebate to the Treasury of all investment income earned in excess of the average coupon on a particular bond issue, with no allowance for the recovery of reasonable costs of issuance.

In addition, the proposal would require issuers to "spend a significant part of bond proceeds within one month" and "all bond proceeds within three years." Such a restriction would mean that bond issues for a long-term construction project would be tied to arbitrary and unrealistic criteria of spending a significant amount of the proceeds over short time periods that have no relation to the size and construction schedules of projects.

Prohibition of Advance Refunding

All advance refundings of tax-exempt bond issues would be prohibited. The proposed prohibition on advance refunding would severely restrict a publicly owned utility's ability to efficiently manage its debt--the way other enterprises do--to lower costs to consumers. The blanket prohibition of advance refundings would limit an issuer's ability to take advantage of lower interest rates, to restructure debt service to match a changing revenue stream, or to mitigate the effects of an overly restrictive bond indenture. In short, it would seriously impair an issuer's ability to exercise sound financial management and increase costs substantially.

Reporting Requirements

The proposal would extend to all tax-exempt bonds the industrial development bond (IDB) reporting requirements. Should issuers fail to file reports, the bonds would lose their tax exemption. This proposal would be both burdensome and unnecessary. This reporting requirement, designed to police the issuance of private purpose industrial development bonds, is totally inappropriate for public purpose obligations.

Taken together, these proposals would discourage efficiency in planning and implementing power supply programs, discriminate against one segment of the electric utility industry, reduce competition among power suppliers, and pose the prospect of higher electric rates throughout the country.

This considerable damage would be inflicted without there being obtained any net benefit of proportionable magnitude - for the U.S. Treasury or anyone else.

AMERICAN PUBLIC POWER ASSOCIATION
2301 M STREET NW WASHINGTON DC 20037 • 202/775-8300

July, 1985

ELECTRIC TRANSMISSION IN THE U.S.: PROBLEMS AND SOLUTIONS

The electric utility industry now has large amounts of surplus generating capacity. This surplus is unevenly distributed throughout the country. Transmission service is a standard function of electric utilities, one which they customarily make available to each other. But where anticompetitive incentives or other barriers exist, utilities have commonly denied others, particularly consumer owned utility systems, transmission services, interconnection, and equitable participation in power coordination arrangements. To make good use of generating capacity surpluses, willing buyers and sellers must have ready access to each other so that the most efficient units can be operated at their optimum dispatchable levels. The barriers which prevent using transmission for efficient dispatch take two forms: institutional obstacles and capacity limitations.

Institutional Obstacles

Twenty years ago, Federal Power Commissioner Charles Ross observed in a hearing before the Senate Commerce Committee that "it is the parties who control the transmission, the arteries of the industry, that control the destiny of the millions of rate payers of this nation." That observation is still true. Access can be, and often is, denied by those in control. The result is that opportunities for economic transactions are lost, and utility ratepayers and the national interest are the losers.

A utility which refuses to wheel (that is, transmit power between two other systems over their own lines) is exposed to potential liability under the antitrust laws. Outright refusals have, therefore, mostly been replaced by subterfuges which achieve the same result. These tactics, encountered by numerous public power systems around the country, include protracted negotiations, unreasonable terms and exorbitant prices. Some examples:

- In California, transmission service from Pacific Gas and Electric Company (PG&E) has been obtained -- when at all -- only through protracted negotiations and by accepting unreasonable terms and conditions. The Northern California Power Agency (NCPA) began negotiations with PG&E for wheeling before 1970, without result. In 1976, as a condition for obtaining a license for the Diablo Canyon nuclear project, PG&E was required by the Nuclear Regulatory Commission to provide wheeling when capacity is available. In 1983 -- 13 years after negotiations started, 7 years after the license condition was imposed -- the FERC approved a "negotiated" wheeling agreement whose terms are highly favorable to PG&E.

Throughout negotiations, PG&E refused to submit controversies to FERC. Among other whimsies, PG&E demands that any transmission service change be filed with and approved by FERC, thus creating a three-month delay. Consequently, NCPA can make no day-to-day "opportunity" changes in operation that could save its consumers money. NCPA, however, is better off than most other Northern California public power systems -- most have no wheeling agreement with PG&E at all, and could face a decade of negotiations to get one.

- Like PG&E, Southern California Edison has actively sought to prevent California consumer owned utilities from gaining access to independent power supplies. Anaheim, California, is an island within Edison's service area; without transmission, it must remain wholly captive. Anaheim has tried to buy energy from the Pacific Northwest, but Edison refused to allow transmission. Anaheim was barred from participating in the Navajo coal-fired powerplant in Arizona when it could not secure transmission through Edison's facilities. Anaheim asked Nevada Power Company, manager of a proposed coal plant, the Henry Allen-Warner Valley Project, for participation in that project; Nevada referred Anaheim to Edison, a project co-owner, which replied that participation requests should be addressed to Nevada; Anaheim wrote to all participants -- without result. In 1979, Anaheim asked Edison for firm transmission for power from the Cholla Generating Project of Arizona Public Service Company. Edison demanded a contractual condition which made the purchase impossible -- and then bought the Cholla power for itself.

- In Florida, Wisconsin, and Kansas, municipal utilities must pay "pancaked" double or multiple wheeling rates to two or more utilities -- in contrast to New England's joint rates for transmission across the lines of multiple utilities. Kansas municipals anticipate an allocation of economical power from the Western Area Power Administration in 1985 -- but it must be wheeled through up to four utilities, each piling on charges with little relationship to cost. The result -- WAPA waterpower may be unaffordable. In Wisconsin, Northern States Power demands that Wisconsin Public Power, Inc. (WPPI) pay double charges to NSP Wisconsin and NSP Minnesota -- even though the two companies are fully integrated, both financially and operationally. WPPI and its ratepayers have thus foregone economical power supply arrangements available both from Manitoba Hydro and Minnesota Power Company.

- In Florida, municipal systems dependent on transmission by Florida Power and Light are unable to take advantage of economical short-term transactions with other utilities. FP&L refuses to file a transmission tariff and will deal only on a contract-by-contract basis. By the time negotiation can be concluded, opportunities have passed.

- Kentucky Utilities has refused to wheel power from the Southeastern Power Administration to eight Kentucky cities since 1974. A 1980 SEPA complaint to FERC resulted in a decision that the Commission had no authority to order KU to wheel under the Public Utilities Regulatory Policy Act of 1978 (PURPA) because such wheeling would not "reasonably preserve existing competitive relationships," as PURPA requires. The Department of Justice began an antitrust action to compel KU to wheel the SEPA power in 1981. The case is now in discovery with a projected trial date of March, 1986.

- The giant American Electric Power Corporation forces other utilities dependent on its monopoly ownership of transmission to forego short-term and opportunity sales and purchases. AEP will not sell transmission service in less than 12-month time segments, and imposes unreasonable notice requirements. A utility which uses transmission for one day must pay for 12 months, and in some cases must make a formal request 60 days in advance for reservation of capacity for no less than one year. The upshot is that AEP acquires a competitive advantage over other generating utilities through its control of the transmission system. It is ensured access to markets closed to others.

- Wisconsin Electric Company has filed wheeling rates, but it interprets the terms of the tariff to define all transactions as firm, thus pricing them at high, firm wheeling rates rather than lower interruptible rates. Wisconsin Public Power, Inc., a publicly owned power agency dependent on Wisconsin Electric transmission services, states that only about half of its transactions are in fact firm.

Capacity Limitations

Most electric transmission lines have been constructed by individual utility systems to move a specific block of power from designated sources to load centers over a certain period of time. These lines have generally been constructed without regard to regional transmission needs. Thus, while they occupy valuable transmission corridors or rights-of-way, they were not designed to make the most efficient use of these corridors for the benefit of all utilities within the regions served. Today, we are witnessing capacity limitations which are a direct consequence of this piecemeal approach to transmission line construction. Such limitations are now affecting systems in California and the Southwest (restricting energy transfers from the Northwest and the Rocky Mountain area), the upper Midwest, Florida, New England (restricting transfers from New York and Canada), and elsewhere.

Capacity limitations can be addressed by various means, including upgrading existing facilities, building parallel transmission lines, and building new lines over new corridors. Where new lines are constructed, they can be sized to accommodate not simply the needs of one individual utility, but the needs of all utilities within the region.

In the past, the federal government has recognized the importance of accommodating the transmission needs of the power marketing administrations to ensure that federally generated power can be delivered to its intended customers -- local public power systems and rural electric cooperatives. Specifically, regulations governing granting of transmission line rights-of-way over lands under the jurisdiction of the Bureau of Land Management, the Fish and Wildlife Service, and the Forest Service required utility recipients of such rights-of-way to agree to make available excess transmission capacity to move federal power. These requirements (called "wheeling stipulations") encouraged land conservation and avoided unnecessary environmental impacts which would have resulted if the government had been forced to construct duplicate lines in order to move federal power. Unfortunately, even this limited attempt by the federal government to encourage optimum use of existing facilities has met with vigorous opposition from the investor owned utilities. These wheeling stipulation provisions, which had been part of the federal land use regulations for years, have been systematically eliminated in the last few years.

Existing rights-of-way anywhere -- on or off federal lands -- have enormous value as a national public resource. Where they can be expanded to move more electricity, without dedicating new land to utility corridors, the public interest in encouraging that recourse is substantial.

"Insufficient capacity" on existing lines is probably the most common justification given for refusing to wheel power. The claim is often suspect, as is testified by numerous findings by the Nuclear Regulatory Commission in antitrust reviews conducted before nuclear plant licenses are granted. These reviews have repeatedly resulted in the provision of transmission services for small utilities via previously "nonexistent" capacity.

But when the claim is true, the problem is largely soluble by increasing transmission capacity on existing rights-of-way, and that solution is far better than any likely alternatives. For it to be realized, however, there must be federal authority to order utilities to increase transmission capacity on payment of just compensation. Further, if there were such federal authority, it is quite possible that utilities would claim they have "insufficient capacity" for wheeling only when that is in fact the case.

When transmission gaps exist, new lines over new corridors are needed. They face many obstacles, of which siting may be the most difficult -- for aesthetic, health and safety, competing land use, and other reasons. These barriers make new transmission paths a scarce and precious resource, too valuable to allocate inefficiently.

Whether the need is new transmission development or improving the networks we have, meeting it requires: sizing and assigning shares of lines to take into account the reasonably foreseeable needs of all utilities in the affected region; standardizing methods to determine how costs should be shared; and opening up transmission planning so that all affected utilities participate in decisions on questions such as reliability, economics, and adequacy.

The Inadequacy of Federal Law

Congress addressed the need for stronger federal authority to require transmission services in the Public Utilities Regulatory Policy Act of 1978 (PURPA), but power company opposition produced final language which added nothing to Federal Energy Regulatory Commission authority to order wheeling.

The most serious obstacle to using PURPA to obtain access to transmission services is the FERC's interpretation of Section 211's requirement that any FERC order "reasonably preserve existing competitive relationships." An important reason for utilities to seek wheeling is precisely to obtain cheaper, competitive power supplies. If there is to be competition, almost invariably the existing supply contracts will change from time to time as the parties identify and secure more desirable alternatives. However, the FERC has interpreted its own authority under PURPA so narrowly that the Commission would be precluded from issuing a PURPA wheeling order if it enabled competition to work so that one supplier would be replaced by another. Such wheeling orders would increase competition, a result heretofore thought to be desirable in America. The FERC's interpretation of the PURPA provision endorses the strange proposition that enhancement of competition is a bad thing, that a utility has some transcendent rights over its wholesale customers and that the utility's sales to them should be insulated from price competition.

In the only wheeling case to be decided by FERC under PURPA, the Commission refused on just such grounds to order Kentucky Utilities Company to wheel power for a federal power agency to eight municipal utilities in Kentucky. It concluded that the wheeling would not have reasonably preserved existing competitive relationships, because one supplier would have been partially replaced by another. Such a narrow interpretation of Section 211 and other restrictive provisions of PURPA make it very doubtful that any purchasing utility will ever obtain a wheeling order from the Commission.

In some cases, wheeling services have been obtained through the antitrust laws. Under antitrust provisions of the Atomic Energy Act, for example, numerous utilities have been forced to make reserve coordination, transmission, and coordinated planning services available to other utilities in their area, including the small utilities which have suffered most from anticompetitive refusals to wheel. The Atomic Energy Act provides for antitrust review and hearings before the Nuclear Regulatory Commission can approve nuclear powerplant construction or operation. The result has been greatly increased access to transmission services, allowing many small utilities to survive, and with none of the economic injury and reduced reliability claimed by previously reluctant transmission providers.

But these benefits under the Atomic Energy Act apply only when a license for a new nuclear plant is applied for. Antitrust proceedings under the federal antitrust laws are exceedingly time-consuming and expensive. Forcing resort to them ensures that abuses will largely go uncorrected.

How the Nation Would Benefit from Better Use of Transmission

Congressional action to encourage optimum use of transmission facilities would provide tremendous benefits to the nation:

- Inefficient plants that produce high-cost kilowatthours could be mothballed, and expensive, unneeded new construction could be deferred, by increasing power transfers from highly efficient lower-cost plants in other regions.

- Surplus coal-fired, nuclear, and hydroelectric generation could back off oil or gas-fired generation. Today, in some places, coal, nuclear, or water-based generating plants operate below capacity, while distant systems that could buy the power keep burning oil and gas. Excess hydropower from the Pacific Northwest could displace more than 3,000 MW of oil and gas-fired generating capacity in California and Southern Nevada -- but there are no facilities to transmit the power.

- Economic dispatch, power brokering, and pooling arrangements could be expanded regionally and interregionally, with effective and equitable participation. When utilities are interconnected and establish such arrangements, each system can call on units of other systems to provide cheaper energy than it can generate itself to meet, for example, peakload needs, or to provide substitute energy when a unit is down for scheduled maintenance.

- Powerplants could be sited at the most economic and environmentally benign locations. Within an interconnected system, electric utilities may join together to construct powerplants. The energy can be delivered anywhere within the system -- so new units can be built at sites which are environmentally desirable; take maximum advantage of existing transmission; and decrease losses of electricity due to transmission over long distances.

- Smaller systems would have access to competitive bulk power supply sources. Electric utilities which buy wholesale power for part or all of their needs are frequently islands within the service area of a larger utility system. Refusals to wheel have in the past been used as a means of keeping customers captive who have no choice but to pay exorbitant prices for wholesale power.

Recommendations

To realize the potential national benefits of optimum transmission use, the American Public Power Association recommends that:

1. Congress give the Federal Energy Regulatory Commission workable authority to order transmission service on existing lines on fair and nondiscriminatory terms to all sectors of the industry, and, when necessary, to order increases in transmission capacity upon payment of just and reasonable compensation.

2. Congress investigate methods to ensure that all future extra high voltage transmission lines are sized to meet the reasonably foreseeable needs of all utilities in the area upon payment of appropriate compensation and that access to such lines is provided to all systems requesting it on just and reasonable terms.

3. The Federal Energy Regulatory Commission establish an information data base covering transmission and wheeling contracts, to be published by the FERC in tabular form setting forth the key elements in each arrangement and the conditions pertaining to each type of service, for the purpose of obtaining an adequate base on which to set guidelines for just and reasonable rates for transmission services.

-- The American Public Power Association is the national service organization representing over 1,750 local publicly owned electric systems throughout the country.

The CHAIRMAN. I thank you.
Bob?

STATEMENT OF BOB BERGLAND, EXECUTIVE VICE PRESIDENT, NATIONAL RURAL ELECTRIC COOPERATIVE ASSOCIATION

Mr. BERGLAND. Thank you very much, Mr. Chairman. I've shortened up my statement considerably in the interest of time.

I am the executive vice president of the National Rural Electric Cooperative Association. We have about 1,000 consumer-owned electric cooperatives supplying central station electricity to 25 million persons in 46 States.

Our cooperatives, like other utility entities, get power from variety of sources. The distribution cooperatives that supply power directly to consumers in about 70 percent of the country obtain about 30 percent of their needs from Federal power marketing agencies and the TVA. They buy another 25 percent from investor-owned utilities, and buy about 45 percent through their own generating and transmission cooperatives, known as G&T's.

Our G&T cooperatives are doing their part to assure a reliable future of power supply. They have invested about $20 billion for the 25,000 megawatts of capacity now in service, and an additional $11 billion in capacity under construction.

In addition, we're participants in 21 joint nuclear power ventures with investor-owned and public utilities.

Load forecasting is not simple these days. We're all experiencing difficulties in this matter, but Rural Electric's sales, for example, after 3 years of slow growth, rebounded strongly last year with kilowatt hour sales increasing by about 6.6 percent, according to data soon to be published in the REA Annual Report. Much of this spurt resulted from increases in commercial and industrial sales and extremes in the weather.

To complete plants under construction, very little is being done to add to new baseload generation. Commitments for new major generating units in the United States have stopped. In this sense, it appears that the industry may be marking time for the remainder of the eighties, but the North American Reliability Council believes that after 1990, installed generating capacity in some regions will be near the minimum levels and this virtual stoppage is generally brought on by unprecedented cost increases and construction delays.

Regional power surpluses brought on by declining economic conditions and the attendant failure of specific large loads to materialize have also contributed to the industry's problems. It's not only been traditional, but wise, for the industry to have some surplus power. Any responsible utility should have adequate reserves to allow for maintenance and emergencies, as well as to meet new loads and normal growth.

In the past, when powerplants were much less expensive, a large plant on a utility system that was not loaded had little impact on rates. Now, however, with electricity from new coal-fired plants costing as much as 5 to 8 cents a kilowatt and 10 to 15 cents per kilowatt hour for nuclear plant, the impact of the partially idle powerplant on rates is horrendous.

One of our own worst problems is the unplanned surplus. Today, losing a large potential load can play havoc with a small utility. An example is the Big Rivers G&T in Kentucky. Big Rivers built a 400 megawatt coal-fired steamplant to meet the increased load growth of an aluminum plant on their system and in anticipation of helping to serve a large synthetic fuel plant. They did an excellent job in building this plant, brought it on line at reasonable cost, but they are unable to sell the power, due to the cancellation of a synthetic fuel plant and a decline in the economy which reduced the alumimum plant's demand for power.

The situation was worsened when the aluminum company announced its intentions to shut down the plant if there was any rate increase. The loss of an anticipated load is nothing new in the industry, but combined with other factors the impact can be devastating.

Another kind of problem is illustrated in the case of Wabash G&T in Indiana. Wabash has invested some $485 million for a 17 percent ownership in a joint nuclear powerplant with Public Service Company of Indiana. Construction of this plant has been terminated by the PSI and Wabash finds itself facing an immediate rate increase of 50 percent or greater to pay for an investment in a nuclear powerplant which will never operate, through no fault of our own.

I'm frank to say to this committee that we have other G&T's that are or will be experiencing financial difficulties. Their situation is not unlike many other public and private utilities. I want to make it clear that we're not seeking forgiveness of debt; we always pay our bills, and we're proud of our history, but we do have a very serious problem.

I believe one way to improve the power situation and help solve the surplus power of the industry would be to strengthen the interconnected transmission system of this country and to provide adequate access to the grid. A strengthened transmission system and easier access to maintain transmission lines could significanty ease the financial and rate pressure on utilities which find themselves with an unexpected surplus and could help to create a climate more conducive to constructing new generating capacity.

We believe that utilities should be encouraged, perhaps even mandated, to wheel power at a reasonable cost. This is long talked-of reform which could be of immense benefit to all consumers. In the short term, it could play a significant role in easing regional shortages and utilizing surpluses. In the longer term, greater access to wheeling could mean not only more efficient utilization of electricity and investment, but also conservation of all our energy fuels, hydroelectric or thermal.

Much has been done to improve the Nation's ability to move power. Some notable examples are the Pacific Northwest, the Southwest Intertie, the Missouri Basin Systems Group, and other power pools. All of these contribute to and enable the participating utilities to better serve their requirements.

We are presently importing very large amounts of power from Canada at higher rates than would be charged if reasonable wheeling and transmission rates and facilities in parts of the United

States were available, and we recommend an all-out effort to strengthen the Nation's interconnected power system.

A further means of augmenting our supply and strengthening our reliability would be to develop more hydroelectric power. The best place to start would be by adding power at existing Federal dams. I am advised that the Upper Mississippi and Ohio Basins have projects at which more than 2,600 megawatts can be developed. The dams are already built, and this power could be brought on with minimal environmental impact, and there are also many existing private dams in the New York/New England region where hydrofacilities could be installed.

We have cooperatives in several States that have hydro powerplants under construction. In addition, the Southwestern Power Resources Association is working with the Corps of Engineers and the Southwest Power Administration to develop hydro at Federal projects in that region.

Mr. Chairman, we stand ready to provide you with detailed information, and we'll answer the questions which you directed to us, in writing, if that pleases the committee.

[The prepared statement of Mr. Bergland follows:]

STATEMENT OF NATIONAL RURAL ELECTRIC COOPERATIVE ASSOCIATION

ON

ELECTRIC POWER SUPPLY IN THE 1990's

COMMITTEE ON ENERGY AND NATURAL RESOURCES
UNITED STATES SENATE

JULY 25, 1985

Mr. Chairman, I am Bob Bergland, Executive Vice President and General Manager of the National Rural Electric Cooperative Association, the national association of over 1000 rural cooperatives which supply central station electricity to more than 25 million people in 46 states.

I appreciate the opportunity to appear before the Committee to discuss this most important subject. Power supply has been fundamental to the success of rural electric cooperatives since the rural electrification program began 50 years ago.

I was raised on a farm which did not have electricity until the Roseau Electric Co-op was established. There were many states where only 2 to 4 percent of farm families were receiving electric power when the rural electrification program was created by Executive Order of President Roosevelt in 1935 and the Rural Electrification Act was passed in 1936. REA has not only relieved the drudgery which was the common lot of every farm woman, but it made American agriculture the envy of the world and the "REA Co-op" sign one of the best known and most respected symbols in rural America.

Our job is to keep the lights burning in the vast land areas we serve, and they will not go out so long as the rural electrification program continues to receive the kind of support that the United States Congress has given it throughout the past five decades.

We do not take our responsibilities lightly. We have a tremendous job to do in utilizing electric power to strengthen the economic fabric of rural America. We do not believe that this nation should ever face an electric power shortage -- no matter how remote an area may be. And we will not, if we plan wisely for the years ahead and continue those programs that have enabled us to provide America with reliable and abundant sources of power thus far.

Our rural electric cooperatives, like other electric utility entities, get power from a variety of sources. The distribution cooperatives that supply power to consumers in about 70 percent of the U.S. obtain 30 percent of their needs from Federal power marketing agencies and the Tennessee Valley Authority, purchase another 25 percent from investor-owned utilities, and buy about 45 percent through their own generating and transmission cooperatives (G&Ts).

Our G&T cooperatives are doing their part to assure a reliable future power supply. The G&Ts have invested some $17 billion for the 25,000 megawatts of generating capacity now in service, and an additional $11 billion in generating capacity under construction. We are participants in 21 joint nuclear power ventures with investor-owned and public utilities.

NRECA, through its technical staff and the Power Supply Committee of the G&T Technical Advisory Committee, closely monitors the power supply situation, utilizing all reliable data and forecast sources. We will not be caught short.

But, load forecasting is not a simple task these days. All utilities are experiencing great difficulties in this regard. Rural electric sales, for example, after three successive years of slow growth, rebounded strongly last year with kilowatt-hour sales increasing by 6.6 percent according to data soon to be published in the REA Annual Statistical Report, Bulletin 1-1. Much of this spurt resulted from increases in commercial and industrial sales, and extremes in the weather.

However, except to complete plants under construction, very little is being done to add new base load generation. Commitments for new major generating units in the United States have virtually stopped. In this sense it appears the electric utility industry may be marking time for the remainder of the 1980s. But the North American Electric Reliability Council believes that after 1990, installed generating capacity in some regions will be near minimum levels. Why this situation?

A number of things have combined to make the power industry move cautiously in developing more base load capacity. First, the cost of building generating facilities of any kind has escalated tremendously. For several decades ending about the time of the first oil embargo, the cost of building power plants was very low and fuel was cheap. Coal-fired plants that cost less than $200 per kilowatt back then now cost $1500 to $2500 per kilowatt. For nuclear installations, costs are varying from $3000 to as high as $5000 per kilowatt. In less than 15 years, the cost of building generating plants has increased tenfold.

Another factor is construction schedules, which have practically doubled. It used to take three to five years to build a coal-fired plant. Today, estimates range from six to ten years. For nuclear, the construction period is up to 14 years. At least part of the explanation for the extended construction periods stems from the burdens of Government regulations and the ever changing requirements of the Nuclear Regulatory Commission. We support the preservation and conservation of our natural resources, but the impact of environmental requirements upon the utility industry have certainly contributed to extending the time schedules and the cost of plant construction. All this has caused electric power rates to rise, and in some instances has depressed load growth.

Regional power surpluses, brought about by declining economic conditions and the attendant failure of specific large loads to materialize, have also contributed to the industry's problems.

It has not only been traditional but wise for the utility industry to have some surplus power. Any responsible utility should have adequate reserves to allow for maintenance and emergencies, as well as to meet new industrial loads and normal load growth caused by our expanding population.

In the past, when power plants were much less expensive to build, a large power plant on a utility system that was not loaded had little impact on rates. However, with electricity from new coal-fired power plants costing as much as 5 to 8 cents per kilowatt-hour and 10 to 15 cents per kilowatt-hour for nuclear power at the plant, the impact of a partially idle plant on power rates is horrendous.

One of our own worst problems is the unplanned surplus. Today, losing a large potential load can play havoc with any small utility. An example is the Big Rivers G&T in Kentucky. Big Rivers built a 400-megawatt coal-fired steam plant to meet the increased load growth of an aluminum plant on their system and in anticipation of helping to serve a very large synthetic fuel plant.

Big Rivers did an excellent job in building this coal-fired plant and brought it on line at reasonable cost, but they are unable to sell the power due to the cancellation of a synthetic fuel plant and a decline in the economy which reduced the aluminum plant's demand for power. The situation was worsened when the aluminum company announced its intention to shut down the plant if there was any rate increase. The loss of an anticipated load is nothing new in the utility industry, but combined with the other factors I have noted, the impact can be devastating.

Another kind of problem is illustrated in the case of Wabash G&T in Indiana. Wabash has invested some $485 million for 17 percent ownership in a joint nuclear power plant venture with the Public Service Company of Indiana. Construction of this plant has been terminated by PSI, and Wabash finds itself facing an immediate rate increase of 50 percent or greater to pay for an investment in a nuclear power plant which will never operate through no fault of the G&T.

Our rural electric cooperatives face an additional difficulty which other electric utilities do not encounter. The Rural Electrification Administration, which was established to facilitate the distribution of electricity and the development of power supplies for our rural people, seems to be trying to do as little as possible to help. I must say to you in all candor, that if the Administration's budget recommendations to the Congress were carried out, many of our co-ops would not be able to keep the lights burning in parts of rural America. Many rural electric consumers would not be able to pay the rates that would be required to keep the cooperative whole and afloat. There is, for example, no alternative to the REA loan guarantee for our G&T co-ops. It is absolutely essential for the rural electric participation, construction, and ownership of generation and transmission facilities. Also, the REA loan guarantees are funded by financial institutions at interest rates reflecting their full costs.

While most of our G&T cooperatives are keeping their heads above water, some of them are experiencing serious financial problems arising from their involvement in the construction of major generation facilities. These projects were entered into because it was judged that they were needed. These decisions were based upon the best information available along with responsible studies of future power requirements. Many of these studies projected large savings in wholesale power costs, particularly for borrowers participating in nuclear units.

The financial troubles of REA borrowers arise from the same causes as those of other utilities: the absence of an anticipated market for power and/or high costs of new generation, due to some factors I have already mentioned, plus high interest rates, extensive cost overruns, and plant cancellations that have increased power rates without adding to the bulk power supply. These problems have had a more severe impact on rural electric cooperatives than other utilities because most cooperatives do not have low-cost embedded plants to blend with costly new units.

It seems reasonable to us to suggest that REA should follow the example of the commercial bankers who have developed innovative refinancing schemes to salvage financially troubled investor-owned utilities. REA should make every effort to "go that extra mile".

I am frank to say to this Committee that we have other G&Ts that are or will be experiencing financial difficulties. Their situation is not unlike many other public and private utilities. I want to make it clear that we do not seek forgiveness of debt. Our members have always paid their bills. They are rightly proud of their long history of meeting their financial obligations. What our people need and what others in the industry need is time to work out these problems. REA is in a position to give our members this time and they should be encouraged to do so.

I believe one way to improve the power situation and to help solve the power surplus of the industry would be to strengthen the interconnected transmission system of this country and to provide adequate access to the grid.

A strengthened transmission system and easier access to transmission lines could significantly ease the financial and rate pressure on utilities which find themselves with an unexpected surplus and could help to create a climate more conducive to constructing new generating capacity.

We believe that utilities should be encouraged, perhaps even mandated to wheel power at reasonable cost. This is a long talked-of reform which could be of immense benefit to all consumers. In the short term, it could play a significant role in easing regional shortages and utilizing surpluses. In the long term, greater access to wheeling can mean not only more efficient utilization of electricity and investment in plant, but also conservation of all our energy fuels--hydroelectric or thermal.

Much has been done to improve the nation's ability to move power. Some notable examples are the Pacific Northwest-Southwest Intertie, the Missouri Basin Systems Group, and other power pools. All of these contribute to and enable the participating utilities to better serve their customers. But bottlenecks and barriers remain which need to be dealt with institutionally and legislatively.

We are presently, for example, importing very large amounts of power from Canada at higher rates than would be charged if reasonable wheeling and transmission rates and facilities in parts of the United States were available. NRECA advocates an all-out effort by all utilities to strengthen the nation's interconnected power system.

A further means of augmenting our country's power supply and strengthening our power systems' reliability in the '90's would be to develop more hydroelectric power. The best place to start would be by adding power at existing Federal dams. I am advised that the Upper Mississippi and Ohio Basins have projects at which more than 2600 megawatts can be developed. Since the dams are already built, this hydroelectric power could be brought on line relatively quickly with minimal environmental impacts. There are also many existing private dams in the New York-New England region where hydro power facilities could be installed.

Today we have cooperatives in Alabama, Arkansas and Vermont that have hydro power plants under construction. Additionally, the Southwestern Power Resources Association is working with the Corps of Engineers and the Southwestern Power Administration to develop hydro power at Federal projects in that region.

There are many opportunities for the development of new water resources projects which could also augment power supply. These new projects will also create new recreational opportunities.

I am sure every member of this Committee shares NRECA's conviction and determination to make certain that every American has a reliable power supply at a reasonable price. We feel the national interest will best be served by the continuation of our heterogeneous power systems in which public power, investor-owned and rural cooperatives provide electricity for America. We believe that competition among these groups tends to improve service and keep rates down.

I became NRECA's General Manager 16 months ago. I took the job because I believe the mission of the organization and its members is of the highest importance to this nation. I plan to stay the course and expect to be on this job working with you and the Executive Branch to protect and improve rural America.

Mr. Chairman, this completes my testimony.

NATIONAL RURAL ELECTRIC COOPERATIVE ASSOCIATION
1800 Massachusetts Avenue, N.W. Washington, D.C. 20036/202-857-9500

August 8, 1985

Mr. David Doane
Majority Staff
Committee on Energy
and Natural Resources
United States Senate
Washington, D.C. 20510

Dear Mr. Doane:

To supplement my statement of July 25 on "Electric Power Supply in the 1990's," enclosed are the answers to questions submitted to the witnesses appearing at the Committee hearing.

1. Will serious shortages of baseload generating capacity occur on individual utility systems by the early 1990's?

   We have indicated in my general statement that we share the views of the North American Electric Reliability Council that there could well be shortages of baseload generating capacity on some utility systems before the mid-1990's. However, if we consider the bulk power supply situation of our own generation and transmission G&T's, we do not anticipate shortages among the generation and transmission cooperatives (G&Ts) before 1990.

2. If such shortages occur, would each utility faced with such a shortage be able to prevent actual interruptions in service by obtaining additional supplies, such as combustion turbine generation or purchased power?

   NRECA believes that shortages on G&T systems could be taken care of provided (1) additional transmission and wheeling arrangements can be obtained at reasonable rates between utilities, and (2) G&T's are afforded an equal opportunity to participate in joint ventures for new generation and transmission facilities so that they can supply their REC members with adequate power at reasonable and competitive rates. For example, 21 of our G&Ts are currently joint owners of large economically sized generation plants. In the future, we question the ability of our G&Ts to commit to additional large-scale generation projects given the policy of REA to refuse loan commitments for new starts.

3. In your forecast of electric power supply, what are the assumptions relating to the retirement schedule for existing generating plants?

   Construction of most of the G&T power plants began after 1960; most plant construction occurred in the 70's; therefore we made no assumptions relating to retirement or life extension policies. In addition, some of our G&Ts have a few small plants on standby.

4. Do electric utilities have an incentive to minimize their investment in new central-station generating plants?

   Yes.

5. If so, what are the factors contributing to the incentive?

   Our rates are based solely on cost and our members own the power systems. Traditionally, the G&Ts have worked hard to provide bulk power to the distribution systems at the lowest reasonable costs consistent with sound business principles.

   Other incentives to minimize investment in such plants include:

   The REA Loan Policy -- Marked changes in REA loan policies which restrict borrowing, including refusal to finance new generation, greatly limit G&Ts' ability to build new power plants. Ultimately this could lead to power shortages.

   The High Cost of New Plants -- Our G&T's have coal-fired plants on their systems which range in price from $1500 to $2500 per kilowatt. As we stated, we have 21 joint participants in nuclear power plants. These plants range in cost from $2500 up to $5000 per kilowatt. The bottom line is that the cost for coal-fired and nuclear plants have increased by more than tenfold in the past 15 years.

   Long Construction Periods -- Construction schedules for baseload and nuclear plants have practically doubled. Coal-fired plants that were built in three to five years now take from six to 10 years. The construction period for nuclear plants can be as much as 14 years.

The above two questions are answered more fully in our statement.

6. To what extent have so-called "rate suppression" decisions by some state public utility commissions increased the risk of future shortages of electric generating capacity?

   In many states, cooperatives like investor-owned utilities are regulated by state public utility commissions. When a state commission feels that rates should be lowered, for whatever reason, the utility must find a way to cover these costs. When rates for cooperative systems are lowered or proposed rate increases disallowed, there is no way to absorb any revenue shortfalls. In some instances the cooperative is unable to pay its bills.

This was part of the problem faced by the Wabash G&T when it had proposed a rate increase to go into effect over a three-year period in order to avoid bankruptcy. The state commission refused to allow the rate increase; REA, which has the authority, refused to extend the loan. Wabash was finally forced to file for bankruptcy.

7. Who should have the responsibility for electric power supply planning, electric utilities or state regulatory commissions?

Certainly the primary responsibility for power supply planning must rest with the utility providing the electric service. We recognize that situations do arise where more than one state may be involved because the bulk power plant is a joint venture. In that case, some action by the state public utility commissions may be required. For example, it is our understanding that when the Indiana PUC advised the Governor that the Marble Hill power was not needed in that state, this announcement ultimately terminated construction because the utility was unable to get additional financing to complete the plant.

The utilities and the state commissions must find better ways to construct new joint transmission facilities which cross state lines.

Legislation which provides the Federal Energy Regulatory Commission with the authority to order access to transmission systems, as well as compelling the enlargement of such systems, is of utmost importance. However, if a utility must increase its transmission line capacity in order to wheel, the wheeling applicant should bear on a fully allocated basis all capital and operating costs related to wheeling.

Last year at our 43rd annual meeting in New Orleans, our membership passed a resolution on access to wheeling at reasonable rates, a copy of which is attached.

Sincerely,

Bob Bergland
Executive Vice President

Attachment

BB:ajl

RESOLUTION

FROM: Power and Generation Committee

APPROVED BY: Resolutions Committee

SUBJECT: Access to Wheeling at Reasonable Rates

Access to transmission facilities at reasonable rates is necessary to enable this nation's rural electric cooperatives to purchase and sell electric power and thus equitably and effectively serve their respective consumers.

Where the parties are unable to reach a mutually satisfactory agreement, we recognize the necessity for the Federal Energy Regulatory Commission (FERC) to have the authority to order interconnection, wheeling and the increase in transmission capacity. We therefore urge that existing federal law be changed to give authority to the FERC, upon application by an electric utility, after showing that good-faith efforts have been made to negotiate wheeling arrangements, to issue orders to the owner(s) of such facilities to require interconnection and wheeling at reasonable and compensatory rates. However, if such an order requires the utility subject to the order to increase its transmission line capacity, the order shall require the wheeling applicant to bear, on a fully allocated basis, all capital and operating costs related thereto.

The CHAIRMAN. Thank you very much. I appreciate it.

Mr. Mohre, we have your prepared statement. It will be placed in the record in full. If you care to make a few brief remarks, we would welcome that as well.

STATEMENT OF DAVID LEE MOHRE, EXECUTIVE VICE PRESIDENT AND GENERAL MANAGER, CAJUN ELECTRIC POWER COOPERATIVE, INC.

Mr. MOHRE. Yes, Mr. Chairman, thank you.

I'm David Mohre. I'm executive vice president and General Manager of Cajun Electric Power Cooperative, one of the G&T's that Bob Bergland spoke of. We supply electricity to 80 percent of the State of Louisiana. We produce it and distribute it ourselves.

I'd like to briefly update the Committee on a couple issues. One is that in response to the question on the 1995 adequacy of reserves, in the Southwest Power Pool we do in fact have a sufficient adequate capacity margin to meet our needs. The problem is very simple. The problem is, of the 12,000 megawatts of capacity needed to meet that commitment, about 6,000 coal and nuclear—excuse me—coal and lignite is currently on hold. That represents about 60 million barrels of oil annually which, if these plants are not built, will be generated with oil and natural gas in the Southwest.

With regard to the availability of short-term remedies, in case we do get into capacity shortage situations, I believe it is correct to say, with the addition of some transmission that is currently planned and under construction, we will be able to meet load unless, of course, the economic activity increases dramatically.

However, the problem is, again, if we are to meet that increased load, we're talking about increased oil and natural gas use. Again, those plants represent 60 million barrels of oil. And I'd like to come back to that in a few minutes.

The suggestion has been made that we can build peaking turbines if we get into a capacity short situation. As a practical matter, I would like to point out to the committee a couple things. One is, many of the large manufacturers of combustion equipment and turbine generators have closed their plants. As utilities found out a long time ago when they switched from coal to oil and they had to go back to coal, the expertise is gone. And I think that is a potential problem in the future, and we should be able to do things to solve that problem.

The other issue is, if we go in that direction, will the gas be available? Is it consistent with national energy policy? And, quite frankly, will utilities be able to use natural gas for peaking?

Briefly, the rest of my paper deals with what I find personally is a little bit of inconsistency between public energy policy, tax policy, and transportation policy. It's particularly prevalent in the Southwest where, for instance, under the Industrial Fuel Use Act, Cajun as a power supplier was required to build a coal plant, the first coal plant in Louisiana to supply load. To do that, we had to bring coal from Wyoming 1,200 miles to St. Louis, ship it down the Mississippi another 800 miles, and burn it in Louisiana.

And because of the actions of Cajun, about 12 million barrels of oil a year, equivalent of oil and natural gas, are not being used in the State of Louisiana for power generation. Down there, as I'm sure you're aware, the power generation used to be all oil and natural gas.

The point I'm trying to make is that, because of the actions, the interaction of what utilities have done in response to FUA, the Industrial Fuel Use Act, we are in fact freeing up an awful lot of oil and natural gas particularly, and particularly in the Southwest.

There's a little bit of an anomaly here because PURPA which was passed in the same year, 1978, encourages the use of small power production and of course cogeneration. And as my statement said, we believe in cogeneration for generation of electricity through waste, through garbage, waste heat, those kinds of streams. But the areas of the country where cogeneration interest is rampant can be defined by the States of Louisiana and Texas. And I assure you, sir, in those States they're not talking about using waste heat, garbage; they're talking about using natural gas.

And here again, an anomaly between the energy policy of this country, which I believe is conserve oil and gas and increase the use of coal. And what's practically happened as a result of the interaction of these two policies is exactly the opposite, and I think that needs to be addressed.

That kind of inconsistency is part of the uncertainty that you wanted to get at, according to your questions. And I think it deserves some considerable note. Again, I come back to Cajun's units alone, the first coal unit ever built in Louisiana, are saving 18 million barrels of oil a year equivalent. Now, I will admit that part of the reason I came to Washington a long time ago was a belief in a national energy policy that says we should conserve oil and gas and we should use our domestically available resources, particularly coal—if I dare say it, nuclear—and alternative and renewable energy resources. And that's where I see this anomaly arising.

We have some further problems, particularly in the Southwest. The large industrial customers who are going to cogeneration, using the gas we freed up and made cheap, that we can't use, are going off our system. What that does, of course, is spread the huge, enormous fixed cost of our coal and nuclear investments over fewer consumers, raising the price and driving more people away from electricity based on coal, nuclear and renewables, and into the natural gas market. And I just basically don't think that is what the Congress wanted when it passed the laws it did pass. I could be wrong.

I've made a brief statement about transportation policy. I don't want to get too far into that; I'm sure it's been covered. Suffice it to say that the transportation policy of the country with regard to the railroad deregulation, the reasons were good, the railroads needed fixing up, they needed some infusion of dollars to make them run better. They're a valuable resource in the same way the utility industry is a valuable resource to this country. However, the problem is that you have to move coal typical a long distance, and when you do that and you're subject to—and I will choose my words carefully here—when you're subject to at least the appearance of the captive shipper phenomenon, it makes you wonder, particularly in view of the—and again, I'll choose my words carefully—perhaps the not-too-strict enforcement of the antimonopoly kinds of practices; and furthermore, quite frankly, an allowance of transferring costs from the captive shippers—I'm sorry—revenue from captive shippers into the economy market, the more competitive market for the railroads.

Just to point out, three-quarters of the cost of burning coal in Louisiana is transportation cost.

There are a couple other things, just briefly, and again it relates to the dichotomy between energy and tax policy. And I want to throw out a few examples, just to make a point, and I quite frankly do not have the answer to the problem, sir.

If it is true we want to use coal and we want to discourage the use of oil and natural gas generally, to save it for the future and to isolate ourselves from the actions of oil cartels or other cartels, then why is it we're increasing the royalties on coal mine on Federal lands? Why is it we're talking about eliminating the 8½ percent coal depletion allowance; at the same time, not fully eliminating the oil depletion allowance?

Most utility contracts call for a change in royalty fees, a change in depletion allowance; it's directly flowed through to the utility buying coal. These things increase the cost of coal compared to oil and natural gas.

Why do we also want to increase our waterway fees when waterway fees dramatically affect the cost of coal, because it's barged on our rivers; it doesn't affect the cost of oil and natural gas which is shipped over pipelines. We'd like to have a pipeline, but we don't have the Federal policy on it.

There are other examples, and I'm trying to summarize very quickly. I would make a plea that the solution to the problems I'm talking about is not necessarily to repeal FUA or change PURPA.

If you repeal FUA, what you're really doing is saying, OK, now that you've invested $3 billion and that money has to be paid back, now you can use the cheap gas that you've developed. That, quite frankly, sir, will not help the problem. It may exacerabate it.

Larry Hobart brought up economic policy. I'm very concerned. I was chairman of the EPRI industrial program, trying to in fact develop ways to use electricity derived from coal and nuclear to help our industries revitalize themselves. We seem to be shipping our primary industries offshore, and from your comments this morning, Mr. Chairman, I know you're concerned about that.

Who's paying for energy policy? And I don't mean to cry wolf, but I think I can make the statement that the people who are paying for energy policy are the ratepayers of public, private, and cooperative utilities who have made the investment in the incremental coal and nuclear plants that are in fact freeing up and making cheap oil and gas in this country. And they're paying one hell of a price, sir.

Part of that deals with the prudency or mismanagement issue but, more fundamentally, if you really look at the issue, part deals with the fact that we are in an increasing cost industry right now. We've had to build those plants during the highest inflation rates and the highest rate of interest. If anyone thought that you'd be building a nuclear plant when the prime rate was 20 percent, no one would have done it.

Mr. Chairman, although I have some other things to say, I believe they're in my statement.

Thank you, sir.

[The prepared statement of Mr. Mohre follows:]

DAVID LEE MOHRE

TESTIMONY BEFORE THE
SENATE COMMITTEE ON
ENERGY AND NATURAL RESOURCES

RE: THE ADEQUACY OF ELECTRIC GENERATION
THROUGH 1995

THURSDAY, JULY 25, 1985

My name is David Lee Mohre. I am Executive Vice President and General Manager of Cajun Electric Power Cooperative, Inc., a generation and transmission cooperative that supplies electricity to over one million rural residents in a service area that covers approximately 80% of the state of Louisiana. I have been in the utility arena for over twenty-two years -- sixteen of which have been with cooperatives and investor-owned utilities. I have also managed federal policy, research and regulatory programs related to the electric utility industry for five years at the Energy Research and Development Administration and later the Department of Energy. During those five years I held the positions of Director of Utility Policy, Chief of Power Distribution and Load Management, and Deputy Director of Power Supply and Reliability, the federal entity responsible for overview of Need for Power issues and enforcing regulations related to Federal Power Act, Industrial Fuel Use Act, the Public Regulatory Policies Act, et.al. I was also Administrator of the Emergency Electric Power Administration, the federal entity responsible for emergency preparedness of the electric utility industry under the Defense Production Act.

I am a graduate of Johns Hopkins University with Bachelor of Science Degrees in Electrical Engineering and Operations Research, and hold a Masters Degree in Business Administration majoring in finance. I am a former member of the Electric Power Research Institute (EPRI)/National Association of Regulatory Utility Commissioners (NARUC) National Rate Design Study Committee, the EPRI Energy Utilization and Conservation Technology Task Force, Chairman of the EPRI Industrial Program, the FERC Advisory Committee on power pooling, and several other energy related organizations. I was also a member of the federal task force on electromagnetic (EMP) pulse effects on power systems.

The purpose of my testimony today is to respond to the Committee's inquiry regarding possible regional shortages of electric power by the early 1990's. Specifically, I will relate from my perspective the situation in the Southwest Power Pool (SPP) in which Cajun operates. I further intend by my testimony to identify specific policy issues that are dramatically increasing the uncertainty in both the planning for and financing of future electric generation, including specifically the impact of current and proposed energy and tax policy at the federal level. Further, to discuss the practical result of current energy legislation on the cost of electricity and the availability and price of oil and gas. Additionally, to discuss my belief that it is often the rate payers of coal and nuclear based utilities that bear the brunt of our nations energy policy, and that this is particularly true for rural cooperative rate payers who proportionately more than any other segment of the industry are underwriting the cost for new coal and nuclear plants in this Nation. My final purpose is to suggest and emphasize that our current adequate capacity situation combined with several well known nuclear problems have probably made us very complacent and short-sighted in our view toward the need for new electric generation, similar to the oft heard short-sighted view that our oil and gas problems are gone forever.

REGIONAL OUTLOOK

With regard to possible regional shortages of generating capacity by the early 1990's, I believe that the current Southwest Power Pool projection of capacity margin will be adequate, i.e. above the 16.7% minimum criteria that the Pool has established, if all planned facilities are constructed. For 1985 the capacity margin for SPP is 27.8%. By 1989 this will fall to 21% and by 1994 drop further to 18%. We must note, however, that if a single planned nuclear plant or coal plant of 2000 megawatts is not completed, it would have the effect of reducing the 1994 capacity margin to below the minimum established, i.e. to slightly below 15%. Although the SPP members plan to increase generating capacity by some 12,167 megawatts over the next ten years, currently twelve out of nineteen large coal/lignite plants scheduled for service by 1994 are still only in the planning stage. The current uncertainty with regard to coal and nuclear generation, energy policy and regulatory treatment may adversely impact this construction program. We will discuss these uncertainties later.

With regard to the Sub-Committee's question regarding the availability of short-term remedies should the SPP get into a capacity shortage situation, the answer may be yes, but if that happens it is likely that we will have to dramatically increase our use of natural gas and oil from the planned 30% energy level to well over 40%. If that occurs the Southwest Power Pool would be using the equivalent of 220 million barrels of oil per year of oil and natural gas for electric generation. At issue here, of course, is (1) would this be consistent with National Energy Policy, (2) would the oil and gas be there, and (3) will electric utilities be able to use them for the generation of electricity.

To meet the Committee's specific emphasis on the forecasting of electric power supply and demand, I would next like to identify and discuss current public policy issues and how they dramatically increase the uncertainties utilities face in planning for and financing new generation.

POLICY ISSUES

Generally the policies and issues that dramatically increase the uncertainty for the industry in the planning and construction of new generation fall into the following broad categories: current federal energy and transportation policies; proposed federal energy and tax policies; general economic policies; and, regulatory treatment.

Federal Energy Policies

I believe it is correct to say that the stated Energy Policy of this nation is to conserve oil and gas so that our children and their children can benefit from these natural resources and also to protect the Nation's economy from OPEC and other energy cartel actions. The specific emphasis, particularly for electric utilities, includes the increased use of domestic energy resources, particularly coal, nuclear and alternative energy. Unfortunately something has happened along the way and the practical result of the legislation that was enacted, I believe, is far different from the intent of the legislation itself, and this is contributing to the uncertainty that utilities face.

The Power Plant and Industrial Fuel Use Act of 1978 basically prohibited electric utilities from building new gas and oil-fired generating units, and generally restricted the use of natural gas as an industrial boiler fuel. When Cajun Electric needed new generation, it was required to invest some $1.2 billion in coal-fired facilities and bring coal from Wyoming to Louisiana - because under the law it could not use the natural gas and oil that was plentiful in Louisiana. As our generation needs grew we purchased a portion of the River Bend Nuclear Facility being built by another utility in Louisiana. In total Cajun has invested some $3 billion dollars in non-oil and gas generation. Other utilities did too. The practical result of this has been to contribute dramatically to the current and forecast enormous supply of inexpensive gas on the market.

Another federal policy promulgated in 1978 was the Public Utility Regulatory Policies Act (PURPA) which among other things puts in place incentives for the production of electricity through small power producers and cogeneration. There is no question that cogeneration has a place in the Nation's energy future. But there are several major risks involved in promoting cogeneration as a means of meeting the future power needs of U. S. consumers, particularly in the southwest area. Some cogeneration facilities perform an important role by utilizing waste materials such as garbage, rice hauls, and waste heat from industrial processes. But in Louisiana and Texas, where cogeneration interest is the highest, virtually all the cogeneration facilities being planned or built will utilize natural gas.

Since most of these cogeneration facilities are to be gas-fired a utility that relies on cogeneration is really increasing its dependence on natural gas using the very gas that was made available by restrictions on utility use. Ironically, the major goal of both PURPA and FUA was to reduce the Nation's reliance on natural gas and oil. With todays natural gas bubble and soft prices, gas-fired cogeneration may appear to be an attractive and logical alternative, however, what happens in a few years when gas supplies are expected to drop. Further, what happens if unregulated cogenerators do not maintain the reliability of their plants, or if the industrial plants close down their cogeneration facilities in response to an upward shift in natural gas prices or change their operation in response to competitive pressures.

I think you will agree that results of these two pieces of energy legislation that were designed to limit the use of oil and gas and increase the use of coal, have had exactly the opposite effect. Indeed, they contribute to additional uncertainty both in the supply and price of natural gas and oil, and, for the electric utility industry that under current law is not allowed to use either for new generation.

Saying it differently, this dichotomy in intent versus reality of these pieces of legislation is that the actions electric utilities have taken in response to being denied the use of natural gas has increased the availability and decreased the price of natural gas, thereby promoting its, use while at the same time increasing the cost of coal and nuclear-based electricity to our other customers as large industrial customers leave our systems. This can't possibly be the result that Congress intended because it promotes the use of natural gas and oil to the detriment of coal-based energy in our nation.

Federal Transportation Policy

Over the past several years there have been several legislative actions that had the effect of deregulating our railroad system. Without going into detail, because I'm certain that other participants before this Committee have covered this far better than I could, I would like to make the following points. Generally if utilities burn coal they need to transport it over large distances and many, like Cajun, must use the railroads. In Cajun's case we use the railroads to bring coal from Wyoming some 1130 miles to St. Louis where it is transferred to barges for shipment down the Mississippi. As with PURPA and FUA, the reasons behind the deregulation of the railroads were appropriate -- unfortunately the actual result has been to penalize captive shippers, like Cajun, by allowing the railroads to subsidize their competitive market customers by overcharging captive shippers. Since the cost to Cajun to ship coal to our plants is 75% of the actual cost of the coal as burned, and because we have little control over what the railroads charge due to the new federal policies, the end result is to, again, increase the cost of coal as a fuel in relation to natural gas and oil.

Further, the lack of a specific coal slurry pipeline policy as a practical alternative to the railroads has only strengthened their position on charges to captive shippers.

Tax Policy

With regard to Tax Policy, although we very much support the Congress' striving to reduce the federal deficit, and are willing to pay our share, several recent proposals continue to thwart our ability to meet national energy policy and provide what our consumers need in a reliable and economic manner. Specifically, the planned increase in royalty fees on coal mined on federal lands dramatically increases the cost of coal relative to oil and natural gas. In 1987 Cajun's coal bill will increase by the difference between the current 20¢ per ton royalty fee and the new royalty fees amounting to to 12-1/2% of the cost of the coal, which is currently about $12.00 per ton. The difference is well over $6.5 million for Cajun's rate payers alone.

Additionally, the current tax proposal includes the elimination of the 8-1/2% depletion allowance on coal. Utility coal contracts are generally such that these type of increased fees and taxes are flowed through directly into the price of coal on a one-to-one basis. This would not be so bad were it not for the fact that we understand that the proposed elimination of the same depletion allowance for oil has been considerably altered. Again the net result is to increase the cost of coal relative to oil and natural gas and, again, encourages the use of oil and natural gas instead of coal.

Another proposal is to increase waterway fees. The current proposal would increase Cajun's coal costs by more than $5 million. Unfortunately such increases will not impact natural gas at all, so again the price of coal relative to natural gas is at a further disadvantage.

There are other examples. But I don't believe that decreasing coal use and increasing natural gas and oil use is what the Congress wants. If, however, current policies remain unchanged and these proposals are enacted, that is what will result. Is it any wonder that under these circumstances the electric utility industry is confused and uncertain by what we perceive to be a serious contradiction between our stated Energy Policy and current and proposed Tax Policy? Under these circumstances, would you invest billions in coal and nuclear plants?

It has been suggested that the solution is to eliminate the restriction on utility use of natural gas and oil. That might work if we could also ignore the enormous investments that has been made in new coal and nuclear plants to meet national Energy Policy and comply with legislation. Cajun alone has invested $3 billion over the last seven years. But these dollars must be paid back and so electric rates will remain high relative to natural gas and oil, thus encouraging their use. Is this appropriate long-term Energy Policy? I don't think so because it will play right back into the hands of those who manipulated us in 1973 and 1979.

Economic Policy

Another uncertainty for utilities is that the current Economic Policy has had the practical result of moving many of our basic industries offshore. Once gone, I find it very difficult to believe that we'll get them back. Generally these types of industries utilize a lot of electricity, while a service economy which we appear headed for generally does not. If this continues the result of even lower electric growth rates will definitely improve our capacity margin situation, but at what cost to America's security and jobs? Since I'm not an expert in the field of economics I should not comment further on the economic results of our current policies, except to say they do substantially increase our planning uncertainty for new generation. On a personal basis, however, I would like to say that I do not believe we can all find jobs at McDonalds, even if we wanted to do so. My instincts tell me a "balanced" economy is preferable to one dominated by either service jobs or some unknown economic miracle.

Who's Paying for Energy Policy

An issue that in my mind is not so uncertain, however, is who is paying for national Energy Policy? For the reasons stated above the actual result of our current Energy and Transportation Policy is that electric consumers of coal and nuclear utilities who have built facilities to substitute for oil and natural gas under recent legislation are paying dearly and specifically for our nation's Energy Policy (In fact, I believe I can argue that they are presently subsidizing the availability and price of natural gas). This is particularly true for rate payers of rural electric cooperatives who, on a proportional basis, are underwriting far more than their fair share of the cost of new nuclear and coal facilities. Now that these rural folks have swallowed more dust and said they are willing to pay higher electric rates to support national Energy Policy for the good of America, some of our leaders are telling them to swallow mud by trying to pull the plug on REA. Should this happen the predictable result will probably be the death of the cooperative systems that electrified 75% of the nation through the efforts of rural people helping themselves -- through takeovers by the very corporations that did not find it "profitable" to supply electricity to rural America. As one who's worked on both sides of the electric utility industry, that just strikes me as grossly inequitable. Rural America electrified itself through its own hard work, and loyally supported America's Energy Policy through its commitment to coal and nuclear power. Rural America deserves better treatment.

SUMMARY

It is my belief that the current satisfactory condition of the electric utility industry capacity margins, plus the enormous problems associated with five or six nuclear plants and current soft oil and gas prices, may have left our industry, our regulators, and our government somewhat complacent and short-sighted -- similar to the philosophy that the oil and gas problems of this Nation are over because there is a current "bubble" and low prices. We've all been admonished at one time or another in our lives that those who do not learn from history are going to repeat it. Personally, I don't believe that our people and our economy could stand another 1973, 1979 or worse. The production of electricity with coal, nuclear, and alternative energy substantially minimizes and mitigates against such risks. We need consistent federal policies in energy, tax, and transportation that will make sense for this Nation. We need effective regulation that is not short-sighted and politically motivated. We also need to do better within the utility industry itself, whether it's controlling the cost of nuclear construction or developing new and more efficient uses of our product to meet our consumers needs and not just worrying about building generation. While we may not need to build additional generation over that which is planned starting today, we certainly need to reduce the uncertainties described above so that we can efficiently and prudently meet tomorrows needs, whatever they are. Considering that under the current situation it generally takes approximately ten years to build a new generating facility we need to reduce those uncertainties as soon as possible. When the OPEC man comes again, and he surely will, we need to be prepared.

The CHAIRMAN. Thank you very much.

Mr. Hobart, you indicate that you don't believe there will be any shortage or substantial risk of shortage by the early 1990's. Are you as confident, if we push that beyond 1995?

Mr. HOBART. No, I'm not confident, Mr. Chairman. That's why I suggested we really do have to seriously consider the whole question of how we're going to plan for that period beyond 1995. The utility industry, as you're well aware, is a capital-intensive industry in its current technology. It is a long-term planning operation, and now is exactly the time to start preparing for the post-1995 period. People have to make decisions, things have to be put in place.

Dave Mohre mentions the vendor problem, as to whether the capacity is there to build the kinds of things we might need. We need to start now.

But let me reinforce something that Bob Bergland said, which I think is very important and could well help us stretch out a little bit the time period that we have to make decisions, and change the way we do business, which is undoubtedly a necessity, and that is this whole issue of transmission, which represents the highways of electricity and part of our national infrastructure. There are great opportunities to enhance our ability to maximize existing investment in generating facilities if we can free up transmission and build those missing links where we cannot now take full advantage of surpluses to move them into areas of deficit; and, equally important, the opportunity to take advantage of seasonal disparities.

In your area, the Pacific Northwest, there is a great opportunity to link with the Southwest, with a new and different intertie. Early calculations suggest that 1,000 megawatts of capacity could be exchanged on a seasonal basis coming from the Northwest in the summer to the Southwest to meet air-conditioning load, and returning to the Northwest in the winter to handle electric heating. That is, on the face of it, a remarkable opportunity to save money for consumers and there are more opportunities like that that should be taken advantage of.

The CHAIRMAN. Well, I am concerned that if indeed we have these great variables, and I think every witness has pointed to the variables, that the safe thing to do is to make no decisions because there's uncertainty. And yet, the lead times are so great that we can't indulge ourselves in the more comfortable policy of avoiding problems in the short term, but allowing them to accumulate in the longer term.

Bob, you indicate that you believe the members of NRECA are going to be able to meet their needs. Does that imply that you have enough capacity for the next 10 or 15 years, that you're confident you're going to be able to make the decisions and start the construction?

Mr. BERGLAND. Mr. Chairman, in the aggregate, we have enough capacity. The problem is location. We have the big surpluses in Kansas and we have developing shortages in the southeast coastal States. It's that kind of difficulty which we have to overcome, and therefore large transmission capacity would help us.

The CHAIRMAN. I assume that the members of the Public Power Association and NRECA, which have much different regulatory climate, are not faced with the same hazards that the imprudency decisions that are made—except as you indicate, that imprudence, by definition, has been the board of directors getting booted out of office.

That's a different penalty to the consumers than might be paid if indeed imprudency simply can't be placed in the baseload. And even if the judgment of imprudency is made, your consumers still pay the bill.

Mr. HOBART. Yes; in fact, Mr. Chairman, I think the penalty that's imposed on a public agency which makes a "mistake" is more severe than that visited on a private company. Among other things, the consumer and the owner of a public power system are one and the same. There are no shareholders on which you can spin off part of the cost that might be regarded as excess. You've got to swallow it.

The CHAIRMAN. Whether that's real or illusion, there's no possibility of even indulging in that.

Mr. HOBART. There's no way to escape. And, furthermore, since these entities are nonprofit institutions, there's no way to lay it off on the taxpayers with a casualty loss on your income tax return either. Forty percent of the cost of a nuclear plant might be handled in that way.

The CHAIRMAN. I've been down that road, and tried to get that done.

Mr. HOBART. I recall.

The CHAIRMAN. And we were not successful in trying to get that done.

Mr. BERGLAND. Mr. Chairman, in about half the States, the co-ops are regulated by the proper authorities. I would say, in addition to that, that when the decision or the choice as to whether this is a mismanagement or imprudent is put to the judgment of our consumer members, it's generally related and called "member unrest. 'They rise up in righteous wrath and vote out the directors and fire managers.

The CHAIRMAN. I'm sure that's true. I notice that occurring here and there. It happened wholesale across the Northwest. But in spite of that, the cost still comes back and is in their rate base. But it also has the effect of saying, just as it would to an investor-owned utility, it says to the follow-on board of directors who are elected because of that unrest, don't take any chances.

Mr. HOBART. Mr. Chairman, I think what it dramatizes also is the fact that we have got to become more sophisticated about how we weigh the options that are available. One of the difficulties in the whole electric utility industry has been weighing energy conservation against a nuclear powerplant. It's sort of an apples and oranges arrangement. We lack experience in doing this kind of thing.

The people that run electric utlilities, certainly large ones, tend to be people who build powerplant. That's how they got famous, got promoted, became the president or whatever. It wasn't the guy that was weatherizing the houses down the street. Yet, it may turn out that weatherization, load management, et cetera, are an essential ingredient in the mix, and somehow they've got to be balanced against that nuclear powerplant. We need analytical tools to help us do that. We're getting more sophisticated: but we need more help.

The **Chairman**. I thank you, all three, very much. I appreciate your testimony and the effort you made in preparing it and being here to testify.

Thank you again. The committee will stand in recess until the hour of 2 p.m.

[Whereupon, at 12:45 p.m. the hearing recessed, to reconvene at 2 p.m., this same day.]

Afternoon Session

Senator **Evans** [presiding]. The hearing will please come to order. This is a continuation of the second day of oversight hearings on the potential for serious regional shortages of electric power in the United States by the early 1990's. We have a distinguished panel before us, Mr. John Siegel, manager of Nuclear Fuel Cycle Projects, Atomic Industrial Forum; John Sillin, manager, Alexander Grant Co. of Washington, DC; Dr. Robert Williams, Senior Research Scientists, Princeton Center for Energy and Environmental Studies; Mr. Michehl Gent, president, North American Electric Reliability Council; Dr. Jan Beyea, Senior Energy Scientist, National Audubon Society; and Mr. Roger F. Naill, vice president, Energy Planning Services, Applied Energy Services, Inc.

Gentlemen, all of the written testimony, as submitted, will be entered into the record in its entirety and I would ask each of you to proceed as you wish, to summarize your testimony, and we'll start with Mr. Siegel. I don't know whether you, Mr. Sillin, are going to be a duo, or if you want to do it separately.

Mr. **Siegel**. We are going to split it up.

STATEMENT OF DR. JOHN R. SIEGEL, MANAGER, NUCLEAR FUEL CYCLE PROJECTS, ATOMIC INDUSTRIAL FORUM; AND JOHN SILLIN, MANAGER, ALEXANDER GRANT CO.

Dr. **Siegel**. We appreciate the opportunity to be here to present our views this morning—or this afternoon. I'd like to emphasize at the outset that these are independent views that we developed some 3 to 4 years ago, and do not represent the views of our respective organizations. Our view is that the Nation is headed for a serious electric supply crisis. Why? Because the demand for electricity is rapidly increasing while rate regulatory disincentives continue to exist regarding investment in major new facilities.

Our policy recommendation for the committee is to deregulate the bulk power sales market for all new generating facilities irrespective of whether they are large or small scale.

Our statement is broken into three segments: A brief statement on the regulatory situation in this country, rate regulatory primarily; a description of our high growth electric event scenario; and, finally, our policy recommendation.

Over 3 years ago when we started writing on this subject, it was quite apparent then that electric utilities had adopted a capital aversion strategy which is predicated, of necessity, in maintaining the financial integrity, and less on providing a reliable supply of electricity. And we recognized then, or at least hypothesized then, that this strategy was biasing their growth projections down. It was predicated on the regulatory situation that we think has only gotten worse.

Today, we hear utilities talk about ordering combustion turbines not because of lead time constraints, but because of regulatory uncertainty.

Last week, FERC denied a construction license to New York Power Authority to build a 1,000 megawatt pumped storage unit in New York State. That construction license was filed in 1977.

The PURPA legislation which was legislated some years ago is being abused in our view. Some utilities encourage and some regulators applaud the addition of alternative or "least cost" energy sources which are neither least cost nor reliable, some of which have been dubbed by Forbes Magazine the "juiciest tax shelters in the land."

We think that this situation which has been described by many is merely is what you get with any industry in which there are excessive price controls and overregulation. It's no different than what was going on in the oil and gas sectors back in the 1970's. At that point, price controls basically discouraged any incentive to supply the consumer who was getting the wrong demand signals. Demand soon outran supply and we had a serious disruption in the oil sector and one in the gas sector. Both of those have now been deregulated.

Unfortunately, that's not true in the electric business. Demand is running ahead of supply now, and there is no new supply seriously being contemplated.

I now want to spend a minute introducing the high growth scenario. High electric growth in the 1980's is based on improved economic growth and electricity's dramatically improved price competitiveness. Sustained economic growth is predicated on a combination of sustained economic growth of 3½ percent and a strengthening in electric content of GNP upward from what has been basically a one-to-one ratio or a little less than that over the past few years, up to a range of 1.3 to 1.5. So we are projecting that the electric content of GNP is going to strengthen. And our forecast is 4 to 5 percent electric growth.

I am going to talk briefly about the sustained economic growth activity component of that forecast, and then John Sillin is going to talk about the implications for electric demand of sustained economic growth.

You can't talk about electric demand without talking about the economy. We think that a 3½ percent sustained rate of growth is achievable. I'll point out that that's somewhat lower than what the administration has been and continues to project.

We think that the economy has the capability to grow at that rate for three reasons: One, the administration's economic policies succeeding; and then two other factors; a structural shift in the labor market and the energy price situation. I'll briefly hit each of those three.

On the administration's economic policies, basically tax cuts and reducing regulatory burdens—we think that is going to succeed and is succeeding. I would point out as one example that the U.S. economy has created close to 20 million jobs in the last 10 years.

Those of Europe have lost 2 million jobs, and today the unemployment rates in Europe are quite a bit higher.

I think this is a reflection of the fact that our tax situation here, the tax take, the Government tax take, has now been reduced to about 33 percent, whereas in Europe it's upwards in the 40 to 50 percent range. I think the energy situation is dramatically changed, and this was a factor that was not apparent to the administration in 1981. If you go back to their budget documents, they were basically assuming that on energy prices, that oil prices and gas prices would continue to increase at rates of, say, 2 to 3 percent—real—per year.

So this is an additional stimulus to the economy that even the administration wasn't counting on when they laid out their economic projections. And, in fact, it's almost yesterday's news. It is yesterday's news, what's happening to the energy market. The only interesting question is how low will oil prices go and where the gas prices, how far are they going to chase the oil market?

The final thing is the structural change in the labor force. Quite unlike the 1970's—and that's the same analogy I should have made with the energy situation—we're looking at mirror images here. On the labor situation, the rate of increase of our labor force began to decline in 1980. We are not economists, but a number of economists have written that this trend bodes well for increased productivity, through higher capital investment. And this capital investment ought to contribute to rising real incomes, rising productivity, as well as the substitution of capital for labor—capital that will run on energy.

Those are the three components of why we think that a 3½ percent rate of economic growth is achievable. The conventional wisdom has been that that rate of growth ought to translate into 3½ percent electric growth.

John Sillin is now going to talk about our view on that correlation.

Mr. SILLIN. Thanks, John.

I just want to spend a few—I have a few charts here, or we have a few charts here. And we just want to spend a few minutes using these charts to present what we think is the significancy and the urgency, if you will, of this upcoming electricity shortage, this shortage again that will be seen by the late 1980's.

Looking at this first chart here, since the first energy crisis of 1973, electricity's market share has increased significantly, growing by some 9 percentage points. Thus, it's become clear that electricity is playing an increasingly larger role in meeting national energy requirements. Thus, any shortfall in supply would have increasingly severe consequences.

In many respects we think that this next chart tells it all in terms of the electricity story and, to some extent, the whole energy story. And again, since the first energy crisis, real oil and natural gas prices to the consumer increased by some 200 percent. In the meantime electricity prices, while they went up, they only went up by 60 percent. The result, as one might expect, the demand for electricity increased and has increased by about 35 percent since the first energy crisis, while non-electric consumption has fallen by

15 percent, thus accounting if you will for that 9 percentage point increase in energy market share for electricity that we just saw.

Now regarding future competitiveness, that is, where is the electricity prices headed and electricity price market share, if you will?

Our point is that despite a lot of rhetoric regarding rate shock for electric prices, on a national basis since 1982, electric prices have actually been falling and have fallen by some 2 percent. It is also our contention that electric prices will continue this downward trend through the rest of the 1980's, again despite what you hear a lot about—rate shock.

Why? No. 1, fuel prices have stabilized or are falling and it was fuel prices which caused the bulk of the electric price increases in the 1970's, caused some three-quarters of those price increases. In addition, growth and demand, growth and demand for electricity is now matching or exceeding the rate of new capacity additions. Thus, unit fixed costs have stablized and in some instances are now falling, and are falling in line with our projections that we made back in 1982.

I might note regarding this price projection chart that you see here, EIA's forecast that they made for real electric prices, while they showed an increase in 1982, their most recent projections seem to be following us down and now show falling electric prices over the next 10 or 15 years.

Now, the resurgence in the economy, growth in energy market share combined with this resurgent economy which Dr. Siegel just talked about, has boosted electric demand since 1982, and growth has matched, in general, our growth forecasts made back in 1982.

Another point I might make: The forecasts made by the low growthers, the soft energy path, if you will, are obviously quite wide of the mark if you look at this chart, and in many respects we believe that their forecasts no longer have any credibility.

What does continuation of the growth rates in this 4 to 5 percent range that Dr. Siegel and I are predicting mean in terms of reliability requirements and when this shortfall will occur? Continuation of current electric growth rates results in reliability problems occurring in the late 1980's and not the 1990's, as described by earlier witnesses; that is, the 20-percent capacity margin referred to generally as that which is needed to adequately meet supply is reached somewhere between 1988 and 1990, depending on whether you get a 4 or a 5 percent electric growth scenario.

This gives the utility industry as little as 3 years to begin adding significant amounts of new capacity. Five years is available at the outside. And by this, I mean that capacity must be coming on line no later than between 3 and 5 years from now; that is, orders should be going on now or should have started a couple of years ago.

Finally, what does this mean in terms of ordering requirements? Well, assuming an average 8-year lead time to build new baseload capacity, beginning this year the industry should be ordering between 30 and 50 gigawatts of new capacity, of new—what we think should be baseload capacity. And, by the way, this assumes that electric growth moderates in the 1990's, falling to a 3 to 4 percent growth range from the 4 to 5 percent electric growth that we're predicting through the rest of this decade, the 1980's.

Just some final observations on these charts. No. 1—particularly this chart—none of the orders which I've just described that are needed are occurring, obviously. Industry witnesses have testified to this already. And even assuming optimistic forecasts by cogeneration and other supports of decentralized generation, you can't get there from here. Estimates of up to 50 gigawatts of decentralized generation being available by the end of this decade, much of which may be uneconomic, amount to at most 1 year's new order requirements, and we believe is at the outside.

In the near term, the industry is likely to be pushed into a combustion turbine ordering mode with obvious negative implications to future electric prices and reliability.

Dr. SIEGEL. Our recommendation to the committee is that the Congress should be enacting legislation which deregulates the supply of new sources of electricity. That is, legislation which allows any entity, utility or not, to construct and operate any size electric plant and to wholesale this plant output at whatever price the market will bear.

Specifically, the price for electricity generated should not be subject to any pricing formula; and new capacity, to be defined to include coal, nuclear, and all centralized as well as decentralized options. This concept is similar to the recent price decontrol of oil and gas supply. I should differentiate. We're talking about supply, not transmission and distribution of electricity. And more narrowly, to some PURPA clauses which open the electric supply sector to certain qualifying facilities and entitites. Our proposal only takes PURPA one step further by letting any entity market the electricity from any new generation source at market rates.

We think the regulation would:

No. 1, result in true competition among the various alternatives, thus encouraging least cost electric supply options.

No. 2, it would provide benefits to suppliers commensurate with risk taken. This ought to enhance management efficiency in the construction and operation of new plants.

No. 3, it would encourage non-utilities to invest in the electric sector. Also, as the electric industry restructures to take advantage of free market opportunities, some rate commissions would be forced to change policies which are not only anti-utility, but also anticentral station technology. This anticentral station bias underscores what we believe is perhaps the greatest irony of the PURPA implemention; that, to a large measure, marginally priced supply options are backing out future baseload generation additions. Thus, the process is institutionalizing higher electric prices.

Finally, we think renewables should be put on the same tax status as central station technologies. Today, windmills and other so-called renewal supply options can avail themselves of large tax breaks. Without these tax subsidies, we think little commercial investment in renewables would be occurring.

Finally, the question of reliability will come up. We think that if a market exists for electricity—and we think there will be a large market—and if a competitor is allowed to compete in this market and earn a fair return on his investment, there will be no shortage of private interests bidding to provide the service.

I think the California cogeneration example provides an excellent example. The Rate Commission there set the avoided cost formula at such a price that you could make a killing providing the service, and literally thousands of entrepreneurs came out of the woodwork.

We think, though, that if a service is provided with conventional baseload technology, that which the United States has used for the better part of the past 100 years, that the reliability of this service will be far better than the hodge-podge of supply options that are currently evolving: windmills with capacity factors of 15 percent, cogeneration supply that could wane at the core business—for example petrochemical refining declines—or Canadian supplies which could be withdrawn in the early 1990's to meet their own internal requirements. This will be exactly at the time when the United States is in a short supply.

That's the end of our oral testimony. We would welcome questions.

[The prepared statement of Dr. Siegel and Mr. Sillin follows:]

STATEMENT

OF

JOHN R. SIEGEL

AND

JOHN O. SILLIN

BEFORE

COMMITTEE ON ENERGY
AND NATURAL RESOURCES

U.S. SENATE

JULY 25, 1985

BACKGROUND

Dr. Siegel is the Special Licensing Projects Manager and the Nuclear Fuel Cycle Projects Manager at the Atomic Industrial Forum. Prior to joining the Forum in 1981, he worked in the strategic energy practice of Booz, Allen & Hamilton. He holds a Doctorate in Engineering Science from Columbia University.

Mr. Sillin is a utility analyst with Alexander Grant & Co., where his work has focused on the areas of utility regulation, planning and operations. Prior to joining Alexander Grant, he held positions with Booz, Allen & Hamilton, the Power Authority of the State of New York, and Commonwealth Services, Inc. He holds a Masters Degree in Business Administration from New York University, and a BA from Franklin and Marshall College.

The views presented are solely those of the authors.

These views represent independent opinions on the economy, energy and electricity prices and electric demand, originally formulated in late 1981 and early 1982. The focus of these arguments is that the U.S. economy has entered a period of sustained economic growth and the combination of an improved economy and electricity's new price competitiveness would produce annual electric demand growth of 4-5% for the 1983-1990 period. And correspondingly, a loss of the nation's 20% electric reserve margin before 1990.

DEREGULATE THE ELECTRIC INDUSTRY

John R. Siegel
and
John O. Sillin

We appreciate the opportunity to present our views to the Committee. We believe the nation is headed for a serious electric supply crisis. Why? Because the demand for electricity is rapidly increasing while rate regulatory disincentives continue to exist regarding investment in major new facilities. The solution: deregulate the bulk power sales market for all new generating facilities irrespective of whether they are large or small scale.

Regulation of the electric industry is not working

To wit:

- Utilities continue to burn oil when a shift to coal would be in the rate-payer's interest and consistent with our national energy policy.
- Utilities discuss commitments to combustion turbines to meet electric demand, citing not lead-time constraints, but "regulatory uncertainty".[1]
- Last week, FERC (Federal Energy Regulatory Commission) denied the New State Power Authorizing a construction license to build a 1000 MWe pumped storage unit in Prattsville, N.Y. The application was filed in 1977.
- The ongoing permitting and financing process for the Seabrook plant would give Lewis Carroll reason to pause.
- PURPA (the Public Utility Regulatory Policy Act of 1978) is being abused. Natural gas and oil use is encouraged. Entreprenneurs are using PURPA to demonstrate the adage, "..a fool and his money are easily separated". In this case, the fool is the ratepayer. Some examples:
    - (Some) utilities encourage, and (some) regulators applaud, the addition of alternative or "least cost" energy sources which are neither least cost nor

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[1] "Indianapolis Utility Shelves Plan to Build A Coal Fired Utility," The Wall Street Journal, March 12, 1985.

reliable; for example, wind sources with the "potential"[2] to produce electricity at 10-15¢/KWHR... double to triple the price of oil; sources dubbed "the juiciest tax shelters in the land" by Forbes magazine;

- FERC is deluged with hundreds of "PURPA" based cogeneration facility applications, many of which are modified jet engines, using as fuels those "dwindling natural resources" which PURPA was designed to save;[3]
- Cogenerators petition to sell utilities electricity at avoided costs and buy it back at industrial rates, in effect, a transfer tax from ratepayer to cogenerator;
- A regulatory commission disallows inclusion in the rate base of a completed coal plant on the premise that it is not "used and useful"...while simultaneously requiring the utility to contract with small producers for power at "avoided costs" higher than the life cycle costs of the coal plant.

You can count on one hand the number of firm commitments for base load power plants in the U.S. since 1978. Of necessity, electric utilities have adopted a "capital aversion strategy" which is predicated more on maintaining financial health and less on providing a reliable and cost effective supply of electricity.

This strategy is the by-product of the existing regulatory process. This process has been characterized by many... "adverserial," "rate-suppressive," "short-sighted," and "politicized."

We prefer a simpler characterization. The electric supply industry (and we differentiate between supply vs. transmission and distribution)--unlike the supply sectors of the gas and oil industry--continues to operate under price controls. As a result, the same inefficiences which exist in any regulated business with excessive government intrusion are now hamstringing the U.S. electric supply sector.

Investment decisions are made with the knowledge that risks will be borne by the stockholder, while benefits flow to the consumer. No wonder the current utility behavior. It is quite predictable, given this un-level playing field.

[2] "Windmills Close the Gap," Energy Daily, February 19, 1985.

[3] Per Table 5.4 in Creating Abundance: America's Least Cost Energy Strategy (by R. Sant, D. Bakke, and R. Naill, McGraw Hill, 1984) 75% of the planned cogeneration capacity additions in the 1980s would use natural gas.

Unfortunately, the consumer--as always--will soon pick up the tab for the inefficiencies of the current system. In effect, the electric sector is painstakingly acting out the final phase of the "energy crisis."

Demand is rapidly outrunning supply. If current trends continue, by the end of 1985 demand will up about 13% since 1982. Supply, only 5%. And only 7% additional supply is under construction.

A shortage is inevitable. The only question is when. Industry and DOE say the early 1990s. Our scenario, which we believe more accurately reflects the changed economy and electricity's improved price competitiveness...the late 1980s. In either case, it is already too late to respond in a cost-effective manner, given the lead times for base load construction.

The implications: electric reliability problems will become wide-spread by 1990; marginal prices will rise as inefficient capacity is thrown on line; and the use of oil and gas to produce electricity will go from 3 MBD (million barrels per day, oil equivalent) today to 8-9 MBD by 1990, putting pressure on oil and gas prices and raising oil imports.

Policy Recommendations: Deregulate the Supply of New Sources of Electricity

Our major recommendation to the Committee is to enact legislation which deregulates the supply of new sources of electricity. That is, legislation which allows any entity--utility or non--to construct and operate any size electric plant and to wholesale the plant output at whatever price the market will bear. Specifically, the price for electricity generated by new capacity should not be subject to any pricing formula. And new capacity to be defined to include coal, nuclear and all other centralized, as well as decentralized options.

This concept is similar to the recent price de-control of oil and gas supply; and more narrowly, PURPA clauses opening the electric supply sector to certain qualifying facilities and entities. Our proposal takes PURPA one step further, by allowing any entity to market the electricity from any new generation source at market rates.

Deregulation of the electric supply sector would:

- Result in true competition among the various alternatives, thus encouraging least cost electric supply options.

- o Provide benefits to suppliers commensurate with risks taken, thus enhancing management efficiency in the construction and operation of new plants.
- o Encourage non-utilities to invest in the electric sector.

Also, as the electric industry restructures to take advantage of free market opportunities, some rate commissions would be forced to change policies which are anti-utility or anti-central station technology.

This anti-central station bias underscores what is perhaps the greatest irony of PURPA's implementation...that to a large measure, marginally priced supply options are backing out future base load generation additions. Thus, the process is institutionalizing higher electric prices.

Finally, windmills and other so-called renewable supply options can presently avail themselves of large tax breaks. Without these tax subsidies, little commercial investment in renewables would occur. Thus in the interest of promoting economic efficiency and fairness, these tax subsidies should be eliminated and the renewables put on the same tax status as central station technologies.

On the question of reliability, we believe that if a market exists for electricity, and if a competitor is allowed to compete in this market and earn a fair return on his investment, there will be no shortage of private interests bidding to provide the service. And if the service is provided with conventional base load technology--that which the U.S. has used for the past 100 years--the reliability of service will be far better than the hodge-podge of supply options that current trends portend: windmills with capacity factors of 15%, co-generation supply which may wane if the core business (e.g., petrochemical refining) declines, or Canadian supplies which could be withdrawn in the early 1990s to meet Canada's own requirements at the exact time the U.S. will be in short supply.

* * * *

The balance of our oral testimony summarizes our high growth electrical demand projection. Responses to your written questions and lengthier written testimony are also attached.

The High Growth Scenario

High electric growth in the 1980s is based on improved economic growth and electricity's dramatically improved price competitiveness. Sustained economic growth averaging 3.5-4% per year, versus the 2.2% of the 1973-1982 period, is predicated on:

- The success of the Administration's economic policy--A long term program focused on controlling inflation through consistent monetary policies and reducing tax and regulatory burdens, thus encouraging incentives to invest in new capital stock
- Stable or falling energy prices--Driven by falling oil prices in the 1980s, versus the 170% run-up in real retail energy prices in the 1970s
- Increased productivity and real income growth--The result of a declining rate of increase in the labor force in the 1980s, in marked contrast to the 1970s, increased capital investment and low inflation.

According to conventional wisdom, 3.5-4% sustained economic growth correlates into 3.5-4% electric growth. But owing to electricity's improved price position (it is 150% more competitively priced today than in 1973), it is probable that the electric growth-to-GNP ratio is turning up:

- Electric penetration into traditional oil and natural gas markets ("cross" price elasticity effects), due to the much greater run-up in oil and gas prices appears to be more than offsetting any reduced electric demand due to "own" price elasticity effects. As a result, electricity continues to increase its energy market share, from 27% in 1973 to 35% in 1984 (Exhibits 1 and 2).
- The relationship of electric growth to GNP appears to be a nonlinear function of the magnitude of GNP...increasing with increasing levels of GNP. This has been the case over the last 30 years and reflects increasing capital spending, a precursor of increased productivity, and personal income gains. Upturns in the ratio of load growth to GNP appear to lag capital spending trends by about 2 years, which, in turn, lag economic upturns by 12-18 months.
- Real electric prices could decline throughout the 1980s--at about a 1.5% annual rate--owing to continued stable fuel prices, increased use of nuclear and coal fuel, and declining unit production costs as reserve margins decline from 41% in 1982 to 20% later in the decade.

Taken in combination, the above suggests that electric growth could accelerate relative to GNP, beginning in 1985.

The Recent Data Should Focus the Electric Debate

Reviewing 1983 and 1984:

- The economy has rebounded strongly. Real GNP has increased about 10% since 1982. Capital spending increased 14% in 1984, the biggest one-year increase in 28 years.

- Retail energy prices are off about 12% since 1982, led by falling oil prices and a general softening in natural gas prices.

- Electric output and peak load increases are exceeding expectations. Each has increased about 8.5% since 1982.

The 1983-1984 data should serve to focus recent arguments on future electric prices and demand:

- The "low-growthers" have been proven wrong--A number of individuals and institutions (particularly those of the soft energy establishment) predicting electric growth rates for the 1980s in the 0-2% range have clearly missed the mark. Exhibit 3 presents actuals versus several mid-1982 estimates.

- Real electric prices are falling--Prices at the national level are off 2% since 1982 (Exhibit 4), in spite of the "expensive" plant now entering service. This falling price trend should accelerate in the late 1980s as less and less plant is put into service.[4] The great "fly-up" in electric prices is rapidly going the way of the natural gas fly-up rhetoric.

- A strong correlation between electric growth and GNP continues to exist--The electric output to GNP (EO/GNP) ratio has averaged .86 the past four years. This correlation continues despite the fact that the impact of higher personal income and accelerating capital investment are only beginning to be felt in the electric sector.

In addition, the electric content of GNP should increase as the cross elasticity effects of electricity's improved price competitiveness increase its energy market share. This hypothesis is supported by the dramatic upturn in electric demand

[4] The Energy Information Agency, in its 1/85 Annual Energy Outlook, now projects falling real electric prices over the next ten years.

which has occurred in the residential and commercial sectors. Over the past five years, demand in these two sectors is running at about 1.5 times the rate of GNP growth. This trend should contribute to a rise in the overall electric content of GNP as the more rapidly growing residential and commercial sectors increase their relative contribution to total electric sales. Since 1979, this has increased from 54% to 61%.

This suggests a question for the Committee to address to other witnesses who may laud conservation to hold down electric demand. Specifically, when you hear testimony on:

- This "energy efficient" office building or that "energy saving device," have the witness explain why electric sales to the commercial sector have risen 22% since 1979,[5] despite rising electric prices in this period, and now prices are falling.
- Energy efficient "home appliances" or "home insulation programs," have the witness explain why electric sales to the residential sector have risen 14% since 1979,[5] despite rising electric prices, and now prices are falling.

We believe the answer is that conservation is by and large a response to price. If prices are not rising significantly faster than real income, conservation will fail. Further, "energy conservation" has translated into increased electric demand due to the greater run-up in oil and gas prices.

A final point worth noting is the very poor correlation between changes in industrial electric sales and GNP since 1979. This would appear to be largely due to little or no change in industrial production since the electric content of industrial production has been steady. This sluggish industrial production appears to be largely a function of the U.S. dollar which appreciated roughly 60% on a trade weighted basis between 1979 and early 1985. The recent decline in the dollar could contribute to a strengthening industrial sector in 1986.

The Economic Outlook for 1985 Continues Positive

The U.S. economy continues to confound critics. The attack on supply-side economics has evolved as follows:

- 1981, "ending inflation would require a decade of slow growth;"

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[5] Source: DOE Monthly Energy Review. Note: Since 1979, GNP increased only 10%.

- 1982, "high interest rates would prevent an economic recovery;"
- 1983, "high interest rates would abort the recovery;" and
- 1984, "the U.S. would slip into recession by early 1985."

Today, the critics continue, equating deficits and the strong U.S. dollar with "the sky is going to fall." Despite all the rhetoric the economic outlook continues positive. Inflation continues to moderate. And given today's enhanced productivity environment--owing to the tax cuts, falling energy prices, and the recent burst in capital spending--inflation should continue at relatively low levels. And without inflation, the traditional recession precursor, the economy should continue on a sustained recovery course.

Presently, the underlying data suggest that the economy is gathering momentum and should accelerate during the second half of 1985, and continue strongly through 1986. In fact, the weather adjusted electric data for the first half of 1985 suggest that either the economy is growing more rapidly than the Commerce Department estimate or the electric content of GNP is strengthening.

Reliability Will Become An Issue By 1990

On a high growth scenario, national reserve margins shrink to 20% by 1990 (Exhibit 5). Reliability problems will manifest in some regions before 1990. The Northeast is one of these regions.

Significant commitments to central station technology are needed today (Exhibit 6). Commitments in the range of 30 to 40 GWe per year. This is not occurring.

Finally, alternative energy sources can not fill this gap. The total supply of alternatives ranges between 30 and 60 GWe by the year 2000, depending on electric price assumptions. This is 1-2 years supply on the high growth scenario.

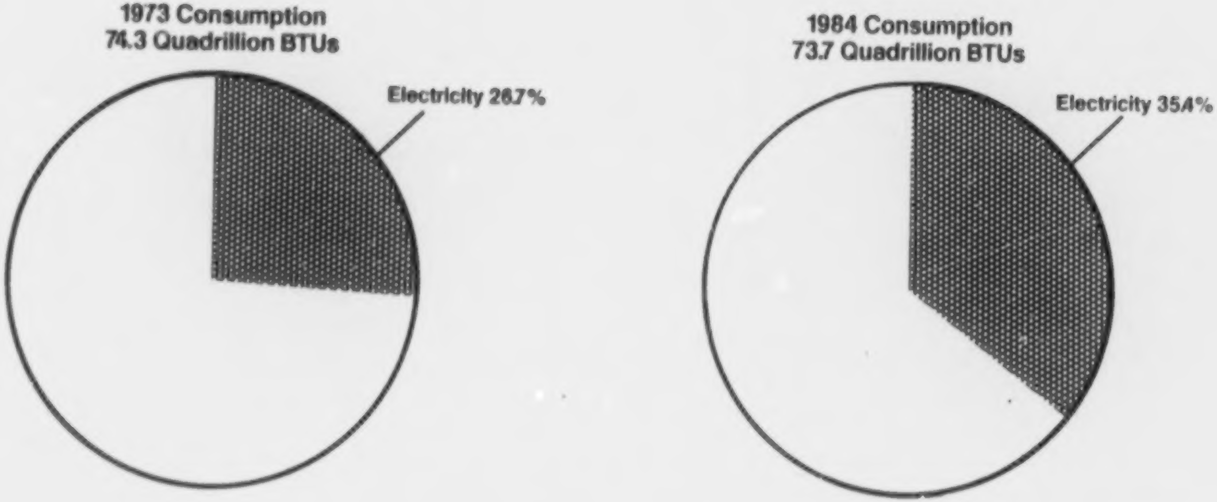
REFERENCES

"Dimming Our Electric Future," John R. Siegel and John O. Sillin, The Wall Street Journal, May 4, 1985.

"The Impending Electricity Crisis," John R. Siegel and John O. Sillin, The New York Times, April 28, 1985.

EXHIBIT 1

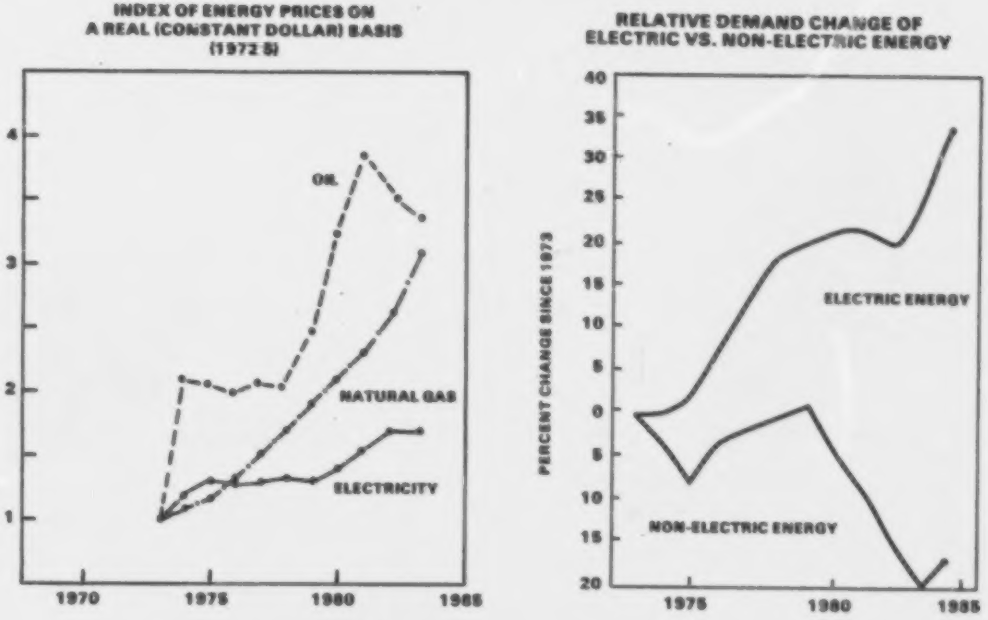
ELECTRICITY'S SHARE OF THE ENERGY MARKET HAS INCREASED SIGNIFICANTLY



Source: DOE/EIA Monthly Energy Review, March 1985

EXHIBIT 2

RECENT RELATIVE PRICE CHANGES OF THE PRIMARY ENERGY COMMODITIES HAVE ENHANCED ELECTRICITY'S MARKET ATTRACTIVENESS



INDEX OF ENERGY PRICES ON
A REAL (CONSTANT DOLLAR) BASIS
(1972 $)

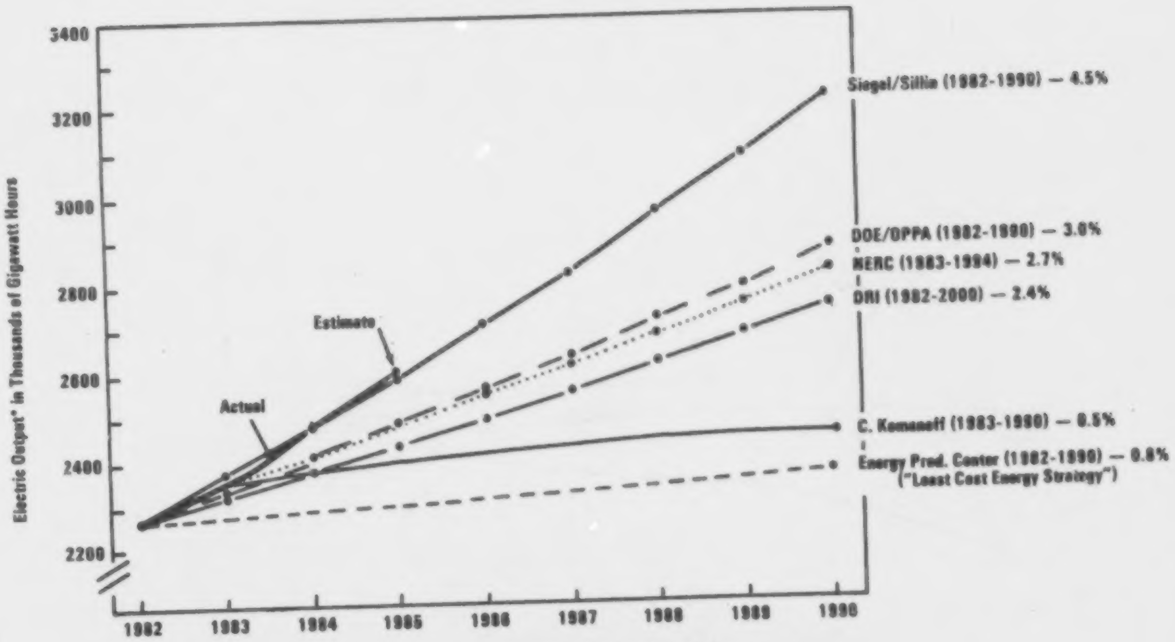
RELATIVE DEMAND CHANGE OF
ELECTRIC VS. NON-ELECTRIC ENERGY

NATURAL GAS — PRICE IS AVERAGE OF RESIDENTIAL HEATING GAS
OIL — PRICE IS AVERAGE OF HOME HEATING OIL
ELECTRICITY — PRICE IS AVERAGE OF RESIDENTIAL, COMMERCIAL AND INDUSTRIAL CHARGE

SOURCE: DOE, *MONTHLY ENERGY REVIEW*

EXHIBIT 3

COMPARISON OF PROJECTED GROWTH IN ELECTRIC OUTPUT

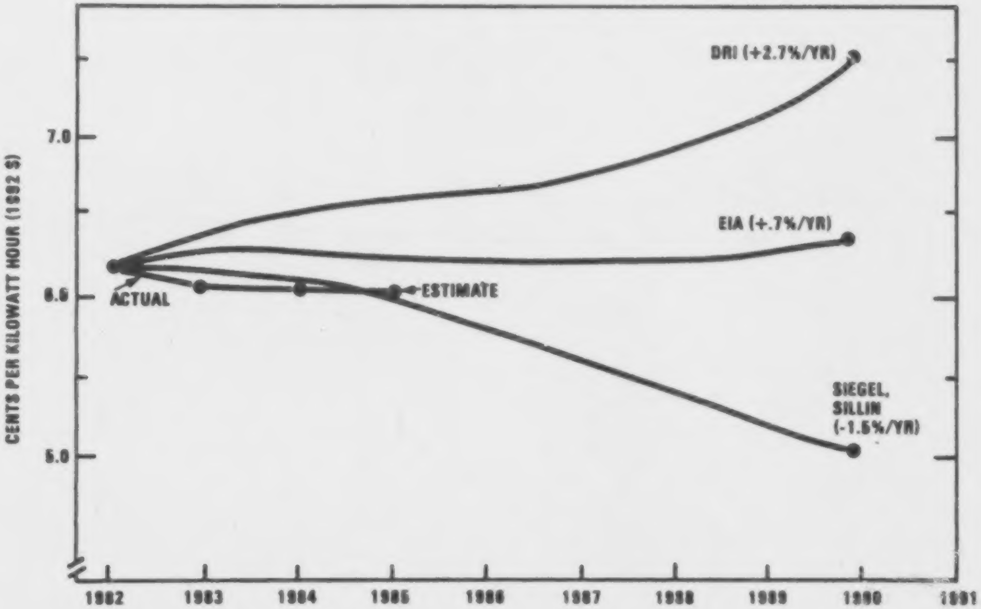


*Electric Output: Total electricity made available for consumption; per EEI "Total Source," Quarterly Report.

NOTE: Due to difficulties in identifying the first forecast year of each projection, and the fact that some projections are changed on an annual basis, 1982 was assumed to be the base year. Exceptions: NERC and C. Komanoff, whose base year was determined to be 1983; 1985 point is an estimate and assumes 4% growth. Sources: Energy productivity center estimate taken from "Eight Great Energy Myths," R.W. Sant and D.W. Bakke, 1981 (Note: 0.8% not a "forecast," but a discussion of a possible outcome if "technology applied on a basis of economic self interest"); C. Komanoff, from Nucleonics Week, 10/84.

EXHIBIT 4

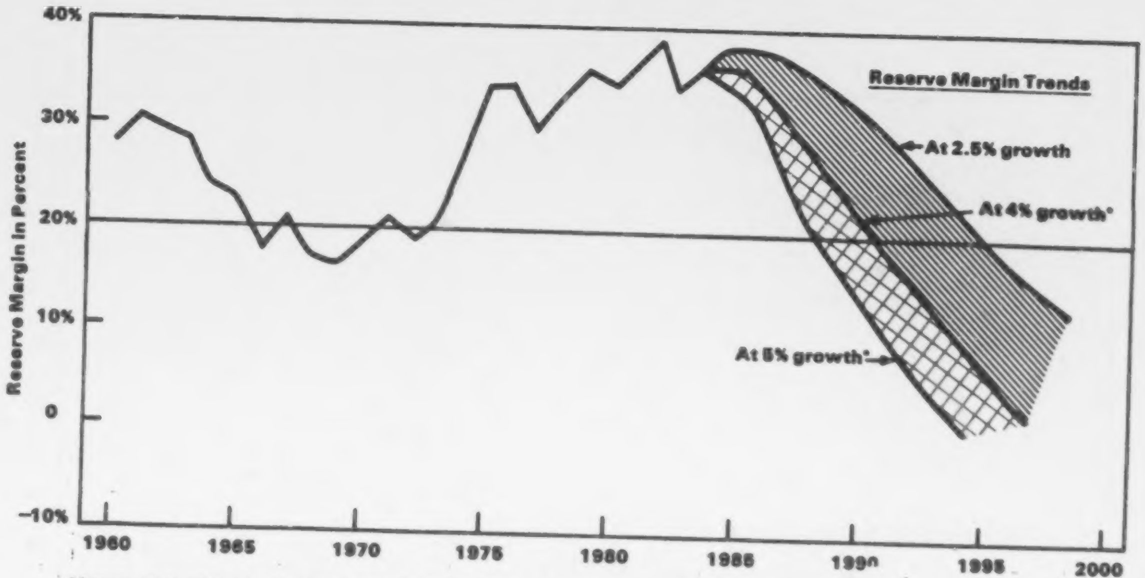
SINCE 1982, REAL ELECTRIC PRICES HAVE BEEN FALLING



SOURCES: J. SIEGEL AND J. SILLIN, "CHANGES IN THE REAL PRICE OF ELECTRICITY: IMPLICATIONS FOR HIGHER GROWTH", *PUBLIC UTILITIES FORTNIGHTLY*, SEPTEMBER 15, 1983. EIA (ENERGY INFORMATION AGENCY) AND DRI (DATA RESOURCES, INC.) PROJECTIONS, TAKEN FROM DOE'S JUNE 1983, *THE FUTURE OF ELECTRIC POWER IN AMERICA.*

EXHIBIT 5

WITH A 4 TO 5% GROWTH SCENARIO, RESERVE MARGINS FALL BELOW 20% BETWEEN 1988 AND 1990



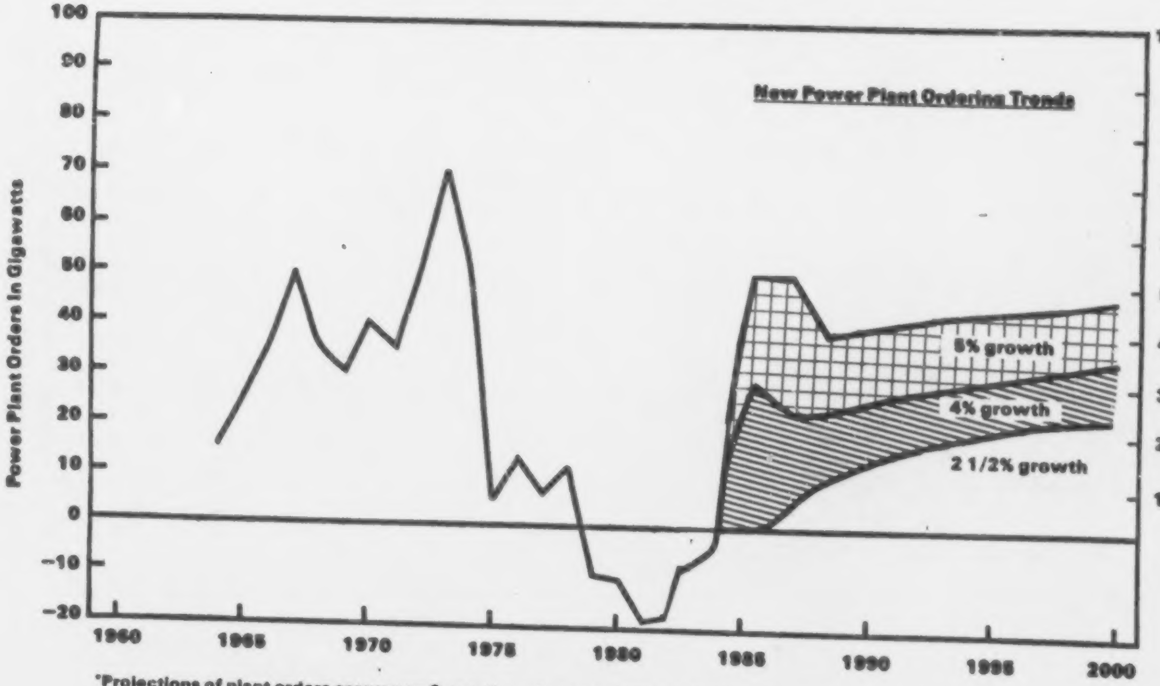
*Assumed: Peak load annual increase of 4% and 5% through 1990, and respectively, 3% and 4% to 2000.

NOTE: Historically, a national reserve margin of approximately 20% has been identified as that which is consistent with reliable electric service. For some regions a reserve margin as low as 15% and as high as 25% may be more appropriate, reflecting regional grid capabilities and peaking phenomena.

Source: Available Resources, 7/84 National Electric Reliability Council "Electric Power Supply and Demand"

EXHIBIT 6

POWER PLANT ORDERING TRENDS AND PROJECTIONS*



*Projections of plant orders assume an 8 year licensing and construction lead time and maintenance of a 20% capacity reserve margin; growth is annual peak load increase; 4% assumed to decrease to 3% after 1990; 5% assumed to decrease to 4% after 1990.

QUESTIONS AND ANSWERS

1. Will serious shortages of baseload generating capacity occur on individual utility systems by the early 1990's?

   Yes, in fact regional shortages could show up in 3-4 years. Exhibit 5 depicts national reserve margins declining to 20% on a high growth electric scenario. Put differently, if the Administration's economic projections of 4% annual GNP growth hold for the 1985-1989 period, electric shortages will manifest no later than 1990.

2. If such shortages occur, would each utility faced with such a shortage be able to prevent actual interruptions in service by obtaining additional supplies, such as combustion turbine generation or purchased power.

   Utilities should be able to prevent major interruptions by placing combustion turbines into services, albeit at a deterioriation of the price and reliability of service. Purchased power is a short-term solution for some regions. In the mid-term--the early 1990s--this supply will be taken back by the selling utility.

3. In your forecast of electric power supply, what are the assumptions relating to the retirement schedule for existing generating plants?

   We use the NERC (National Electric Reliability Council) assumptions. That is, 15 GWe of capacity retired in the 1984-1993 period.

4. Do electric utilities have an incentive to minimize their investment in new central-station generating plants?

   Absolutely.

5. If so, what are the factors contributing to the incentive?

   The current regulatory environment has largely removed the incentive to supply. If an investment is successful, the ratepayer receives all the benefits. If a project runs into any difficulty, the shareholder sees his investment confiscated or reflected in lower stock prices.

6. To what extent have so-called "rate suppression" decisions by some state public utility commissions increased the risk of future shortages of electric generating capacity?

   Because of the rate suppressive environment, utilities are phasing out construction programs for central station technologies, and are depending largely on unproven technologies and strategies such as conservation and alternative energy sources. As demand is increasing, a shortage in inevitable.

7. Who should have the responsibility for electric power supply planning, electric utilities or state regulatory commissions?

   We prefer a deregulation approach to electric power supply planning, thus letting the market interpret demand, the supply implications, and the appropriate modes of supply.

ADDITIONAL WRITTEN REMARKS ON CURRENT ELECTRIC INDUSTRY SUPPLY ISSUE

In a High Growth Environment Current Strategies Will Prove to be Inadequate with Large Potential Risks for Consumers

Given the current industry strategy, one tending to forecast growth on the low side and influenced by a rate regulatory environment not conducive to construction programs, there are a number of issues which portend negatively for the future cost and reliability of the nation's electric supply.

- While uncertainty exists on future electric growth, the low growth scenario appears to be dictating new generation planning decisions--No doubt, uncertainty exists regarding future growth. While conventional wisdom--DOE, NERC, etc.--suggests 2.5-3% annual growth rates, many continue to argue that 1-2% is the correct planning number. Utility planning decisions, however, appear to be driven by low growth projections. Utilities simply are not interested in playing "bet the company."

- In arriving at low growth forecasts, utilities are giving too much credit to conservation and load management--In utility load planning, the low growth bias generally shows up in three areas: a pessimistic view of regional economic conditions; little or no acknowledgement of the potential cross-elasticity effects resulting from the run-up in oil and natural gas prices; and an overestimate of the benefits of conservation and load management. With respect to the first item--economic growth--the strength of the current recovery should work toward putting this issue to rest.

  With respect to the latter two items, it appears that the failure to address cross-price elasticity developments has led to an overestimation of conservation. First, it is not clear how conservation and load management effects can be accurately measured, given electricity's 150% price improvement relative to oil and natural gas. A logical conclusion given this changed price relationship is that customers would "conserve" total energy on an economic basis by restructuring energy factor inputs, but use more electricity. But in developing conservation estimates it appears that forecasters have overlooked this relationship and instead focused primarily on changes in the price of electricity ("own" price elasticity effects).

Further, recent industry forecasts have not recognized the potential for falling electric prices in the 1980s, resulting in a lowering of real electric prices back to 1975 levels. Since most economists define conservation as a price-induced process, as prices fall, demand will increase. This will render "yesterday's" own price elasticity bases for lower electric growth obsolete.

o In Any Event, Demand Limiting Strategies May Have Only Temporary Effects--The industry, particularly rate regulators, should recognize that even if successful, demand limiting strategies may have only a temporary effect in postponing the date when new supply resources will be required. For example, while peak growth may be less* than energy growth, it will be smaller by only a small fraction. Current projections of slowly increasing load factors seem to bear this out. The reasons: weather sensitive loads can be shifted off-peak only with great difficulty; and many industrial and commercial loads continue around the clock, and only small amounts of load can be shifted off-peak without causing significant social and economic dislocations.

o Under High Growth Conditions A Power Import Strategy Will Be Unable To Meet Long Run Energy Needs--As a backup to demand management programs many utilities have indicated they will rely on a strategy of importing "excess" power available from others. Given an outlook for higher growth, there are several reasons why the industry should question this strategy. First, it should be remembered that bulk power sales usually are for limited periods of time, and generally give the seller the option to renegotiate should growth exceed expectations.

Second, it is not clear how much power will be available if importing turns out to be everyone's fallback strategy. For example, many East Coast utilities indicate that they plan to purchase "coal fired" power from the Midwest to meet future requirements, thus eliminating the need to build additional

* And it is possible that peak load growth will exceed electric energy sales, reflecting the high rates of growth in the weather-sensitive residential/commercial sectors.

capacity. But this strategy will not be viable if it is everyone's strategy, and the Midwest coal capacity now thought to be in excess is required to meet internal growth requirements. The same analogy exists regarding proposed hydro power purchases from Canada.

Third, a situation generally overlooked is that economic and electric growth tend to parallel across regions, and in the case of Canada, across international boundaries. As a result, just when a buyer will most need a power purchase agreement to be in force it will most likely be terminated.

- It Is Already Too Late To Deal With The Electricity Supply Issue In A Cost Effective Manner--On the high growth scenario, national electric reserve margins fall below 20% by the end of the decade. Assuming the current "no ordering" stance continues into 1986, the industry will be looking at a 3-4 year lead time to add new capacity. It is difficult if not impossible to add baseload capacity in 3-4 years. Further, the annual average ordering requirements to maintain a 20% reserve margin approximate 40 GWe per year. This is well above the capacity of the power supply infrastructure.

- The Demand for Oil and Natural Gas Will Increase--The electricity industry is painstakingly acting out the final phase of the energy crisis. In the 1970s, price controls on oil and natural gas inhibited the market from working effectively. Producers saw no incentive to develop new supplies at the same time users were consuming at higher rates than would have occurred if prices had been allowed to rise to the market. The result: a supply/demand mismatch, price perturbations, and the U.S. economy muddled through two energy-enhanced recessions.

  Similarly, politicians and rate regulators--by holding down electric prices and not allowing utilities to earn an adequate rate-of-return--are creating an electricity supply/demand mismatch. There is little incentive for utilities to risk capital to increase supplies, particularly when the company's financial health can be held captive by some publicity-seeking State attorney general who has his eye on the governor's spot.

  The main recourse, then, will be to order combustion turbines. This short lead time generating equipment, in conjunction with much higher utilization of existing oil- and gas-fired plants, will increase demand for oil and natural gas from 3 MBPD (million barrels per day, oil equivalent) in 1984 to 8-9 MBPD in 1991. And rising electric prices around 1990 (resulting from higher fuel costs) and questions of reliability may result in some loss of electricity's competitiveness; thus, increased incentives to use oil and gas.

The Soft Energy Path: Cheap Energy or Cheap Shot

One potential supply option involves decentralized sources of generation. Windmills, low head hydro, combined cycle, and cogeneration are examples. But while there has been much discussion of their use, their potential contribution turns out to be rather small. For example, presently there is approximately 30 gigawatts of this type capacity planned for construction over the next 10 years. Even a doubling of this amount would satisfy less than 20% of new plant orders required under a 4% to 5% growth scenario. And a gigawatt of some decentralized sources, e.g., wind, may equal only one-quarter of a gigawatt of conventional cources due to capacity and reliability limitations.

Further, the economics of many alternative, decentralized technologies are uncertain and depend on a combination of favorable regulatory and tax treatments and high oil prices. While the oil market is not cooperating, a few regulatory jurisdictions are. In California, generous state tax policies have made wind energy, according to Forbes magazine, "perhaps the juiciest tax shelter in the land." As a wind energy salesman in California put it: "A project can generate a 122% return in the first year even if the machine don't produce power." Apparently, the only supply constraint on California wind energy development is the supply of taxpayers with incomes to shelter.

A recent "Energy Daily" interview with a wind energy "advocate" noted that new windmill technologies had the "potential" to produce electricity at levelized costs of 10-15 cents/Kwhr...only 2-3 times the price of oil-generated electricity. The article also noted windmill capacity factors were improving nicely (from 4% in 1982 to 13% in 1984). Thus, production costs had plummeted from $1.62/Kwhr to 32 cents/Kwhr. The interview failed to discuss reliability.

A few of the cogeneration projects currently being developed make economic sense and benefit the rate payer. Most, however, represent entrepreneurs taking advantage of "avoided costs" (the price utilities must pay for power purchased under PURPA, the Public Utilities Regulatory Policy Act of 1978) being set at high levels...levels not in the rate payers best interest.

For example. some rate commissions in the Northeast have determined the avoided cost for cogenerated electricity to be in the 9-12 cents/Kwhr range. At these rates, one could turn roughly a 2-5 cents/Kwhr profit making electricity in the garage with a Sears gasoline-driven electric generator! Down South, industrial cogenerators are pressing the rate commission to have electric utilities buy cogenerated electricity at avoided costs, and sell it back at industrial rates. It is a paper transaction, as little or no electricity would leave the industrial site. And in what would be a transfer tax from electric rate payers, the local chemical company is seeking $10-15 million per year from Gulf States Utilities.

Each of the above examples illustrates an unfortunate trend which has developed in the post-PURPA period. I.e., the intent of PURPA is being abused. In each case, the rate payer ends up paying more than the true avoided cost for the power. It does, however, make for a nice profit for the small power producer.

Two final observations. Falling electric prices could further undo the economic feasibility of these sources, sending them the way of the synfuels industry. And PURPA was legislated in part to save our dwindling, precious supplies of gas and oil. Roughly 80% of the cogeneration projects currently planned use natural gas as the primary fuel.

Overall, the soft energy path will not contribute meaningfully in the near- and mid-term to America's energy goals. As Charles Ebinger noted in the October 29, 1984 Wall Street Journal, "Renewable energy (promoters), fueled in large part by liberal visions of decentralized energy systems, were unrealistically optimistic." Further, there is a cost attached to the high avoided costs which justify any Rube Goldberg electric source, that benefit upper income tax shelters...and it is shouldered by poor and middle class electric rate payers. No wonder the NAACP in a late 1970s energy policy statement was suspicious of an overemphasis on the soft energy path--a policy unabashedly based upon the "inevitability of energy shortage"--fearing, quite reasonably, that this shortage would hit the poor first, hardest and for the longest duration.

Reorienting Current Strategies

There are a number of actions utilities can take to reorient their current strategies:

- Buying power on a firm basis at an economic price;
- Purchasing either completed power plants, or those under construction;
- Reviving cancelled or deferred units; and
- Initiating construction of new projects.

Starting today, utilities should make every effort to "lock up" economic sources of generation for as long as possible. The benefit to the buying utility is that it has increased time within which to develop and implement plans which will economically and reliably satisfy future supply requirements.

Alternatively, the sooner it has been perceived that sustained load growth has returned the less available will be the more attractive sources of electricity supply, and the more likely it is that a bidding war will escalate the price of any supplies which are offered for sale.

For utilities unable to lock up supplies on a purchase power basis, and who have no major building programs which will carry them through the rest of the decade, the opportunities associated with buying into existing nuclear and coal facilities need to be investigated. Given the current lead time required to build major facilities, the present may be a rare "window of opportunity" for utilities which would otherwise be capacity short. In this regard, there is now a buyer's market with respect to generating facilities. Utilities who have built little or no capacity since the late 1970s are in a relatively strong financial position; thus they have the resources to buy into major projects.

After exhausting the opportunities described above, resuscitating deferred or cancelled projects may be the fastest, least expensive way to obtain new sources of supply. The conditions which should underlie this include that at least site selection be completed, the engineering be usable, and licensing approvals if not already in hand be well along in the review process.

The last option: analyzing the cost, time and logistics associated with undertaking a new project. Such an analysis would start with an evaluation of the technology options available, and include an assessment of first costs, levelized costs, operating factors, and ordering sizes with respect to individual units. While this feasibility work has frequently been taken for granted, the cost escalations and operating difficulties that have occurred in the recent past indicate that this is the time to test all basic assumptions.

Project planning would include beginning the pre-site selection and approval process and performing preliminary engineering. In addition, the industry must take steps now to standardize plant designs and restore objectivity to the licensing process. If reliable sources of power are going to be available when needed, lead times of no more than five to six years are tolerable. Thus reforms in these areas must be implemented today.

Benefits Accruing from a Revised Strategy

The financial risks associated with undertaking a supply-oriented program are well documented. Construction cost overruns can cost utilities hundreds of millions of dollars. In some instances those developments have threatened utilities with bankruptcy.

The dynamics of this situation start with escalating rates of inflation and interest, whose effects on plant costs are extended as a result of lengthening lead times. In addition, direct costs rise on an inflation-adjusted basis because of increased labor, material, engineering and equipment inputs.

This situation penalizes the utility and its share holders. Regulatory lag, and a general political climate which acts to suppress rates, prevent the utility from increasing revenues at a pace necessary to support increased construction costs. As a result, cash flow deteriorates, dependence on external sources of capital increases, and overall utility financial health declines. Until recently, this situation was compounded by a drop-off in electric load growth. This required utilities to further increase their dependence on the regulatory process in order to sustain necessary revenue growth.

This is the "worst case scenario" which utilities have been living through the last decade, and is the justification used in utility board rooms to defer or cancel major power plant projects. But these decisions may not be appropriate when conditions change. A review of the last three years indicates that financial conditions have improved dramatically, reducing the risks described above and returning the utility industry to a condition approaching that of a declining marginal cost type business.

In addition, under high-growth conditions, plant construction is less likely to be delayed, further reducing the effect of inflation and financing on overall project costs. Under high growth conditions the need for power becomes the paramount issue and serves as an incentive to all participants--including regulators and the general public--to keep plant construction on schedule. Further, increased revenues flowing from higher sales will relieve utilities and rate regulators of some financial pressure. Under these conditions, the cost of new plants will decline in real terms, compared to plant completed in the 1980s.

In a declining cost business there are large potential returns which accrue from a strategy directed at building to meet growth. First, as long as rapid inflation does not distort economics, each additional sale makes an increased contribution to profit as marginal revenue approximates average revenue, but marginal costs drop. Second, for those utilities which have excess capacity, the price premium and profit obtained from external sales will increase as the amount of capacity for sale diminishes, and the competition for resources grows.

Deregulating the Supply of New Sources of Electric Would Enhance the U. S. Electric Supply Picture

Deregulation would result in true competition among the various alternatives, rewards to investors would be commensurate with risks, and non-utilities would be encouraged to invest. For example, independent generating companies could be set up to supply bulk power where demand--and thus a market--exists.

A generating company under a deregulation scenario could take advantage of the economic benefits of its investment by passing significant returns through to the shareholder, instead of the ratepayer which is the situation presently. For example, in the future (and even now in most situations) nuclear generating costs will be as much as 40% lower than the next best alternative (i.e., new coal fired generation). If the generating option turns out to be combustion turbines or some other oil and natural gas-fired alternative, the cost differential turns out to be approximately double. If only a portion of this economic rent is realized, the returns to generating company participants would appear to be extremely attractive.

The first candidates to come to mind for participation in a generating company are electric utilities, either singularly or in combination. But, while utilities have formed generating companies in the past, their transmission and distribution earnings continue to be subject to state PUC regulation; thus, the possibility still exists for regulators to constrain generating company profits. In effect the state PUCs can still hold electric utility investments hostage via the rate making process.

Consequentially, in the future it may be that third parties with little or no stake in distribution would be natural generating company participants. Organizations with the requisite skills and financial resources include vendors, constructors and architect engineers. Even the financial community could participate by putting together an investment consortium to finance all or some portion of the project(s). The fundamental point is that they would be separate and independent from the current utility structure, thus the only constraint on their bargaining position would be electricity market conditions.

In addition, it is not inconceivable that major oil and natural gas producers--who have large cash flows, but limited investment opportunities since their traditional business sector is in decline--may view the electric generating concept as a growth opportunity. They would be diversifying into the growth segment of the energy business, and could bring to bear large technical and financial resources.

The Utility Regulatory/Political Front: Tough Decisions Are Needed

Given the financial and regulatory history of the past decade no utility is likely to undertake a construction program without a clear signal from regulators. Thus, utilities should be aggressively building public, political, and regulatory support for a growth strategy.

Over the past several years, many regulators have emphasized demand side strategies--conservation, energy management, and cogeneration--as the more effective means to provide the consumer the most reliable and cost-effective electric supply. In so doing, and in conjunction with rate requests to complete large base-load power plants, an adversarial relationship has developed between some commissions and utilities.

The adversarial environment has not been universal, however. Some regulatory commissions have recognized that regulators and utilities share a common bond in providing the public a reliable and cost-effective supply of electricity. And further, that sole reliance on alternative or unproven technologies may not achieve this goal, and further carries some uncertainty...and risk for the consumer.

Further, as regulators consider the future they should keep in mind that with excess capacity both the utility and the customer pay. With a capacity shortfall, only the customer pays. Regulators should also recognize that under high growth conditions the electric supply planning pendulum swung past center in 1984. This was due in large part to utility reluctance to commit to new construction programs without the approval of public utility commissions. Of late, continuing strong demand for electricity at rates approximating economic growth is raising questions. Can a demand side strategy , in the long term, assure a reliable, cost-effective supply of electricity?

Momentum on the political front is also needed: specifically, Congress should enact legislation which:

- Deregulates the bulk power sales market;
- Reforms PURPA by repealing provisions which require utilities to buy any and all output from third party producers. This would put central and decentralized supply options in the same market footing;
- Eliminate tax breaks now provided decentralized supply alternatives, and put them on the same tax status as the central station options;
- Enact legislation with regard to the Nuclear Regulatory Commission promoting regulatory stability and design standardization.

Senator EVANS. Fine. I think we'll go through the entire panel first and then we'll get to a series of questions.

Dr. Williams.

STATEMENT OF DR. ROBERT H. WILLIAMS, SENIOR RESEARCH SCIENTIST, CENTER FOR ENERGY AND ENVIRONMENTAL STUDIES, PRINCETON UNIVERSITY

Dr. WILLIAMS. Thank you, Mr. Chairman, and I appreciate the opportunity to participate in this hearing. Listening to the previous speakers, I am very much in sympathy with many of their policy suggestions and I think that those kinds of policies should be considered very seriously. I have a very different, however, perspective on the outlook for electricity demand and how one might deal with this from the point of view of utility planning.

In my testimony I will argue that utility planners should, first, plan for slower electricity demand growth than what is projected in most forecasts, first because of structural shifts in the economy to less energy-intensive activities; and second, because of the economic benefits to the economy of pursuing opportunities for more efficient energy use.

And, second, planners should take advantage of new cost-effective opportunities for short lead time power generation that have recently become available and which can be exploited if electricity demand should grow faster than is planned.

Specifically, I want to make four points.

First, an important development that is inadequately dealt with in most energy demand forecasts is the ongoing structural shift in the U.S. industrial sector away from the processing of basic materials and toward less energy-intensive fabrication and finishing. This shift implies that industrial energy use overall will probably not grow between now and the end of the century and may well decline, and that industrial energy demand will probably grow only at 1 to 2 percent per year.

Second, the opportunities for energy conservation with more efficient electricity end use devices are vast and continually expanding. Capturing these opportunities could slow electricity demand growth almost to a halt.

Third, despite the evidence for less energy-intensive future economic growth and the promise of conservation, the conventional wisdom has been that it is better to overbuild generating capacity, to be prepared to deal with the prospect, however remote, of unforeseeable needs for power and not to be dependent upon hoped-for but uncertain energy savings which may or may not be realized even with promotional utility programs.

And, fourth, despite this, overbuilding is a very costly insurance policy which is no longer necessary because there are cost-effective supply alternatives which can be brought on line quickly, obviating the need to rely on supply technologies with lead times of a decade or more.

In what follows I am going to treat each of these issues in turn, but I will only summarize the written statement and I will not deal with all the points.

First, the ongoing structural change issue. The long-established trend away from goods production and towards services production is widely recognized. What is not so well-known is the pervasive shift underway within industry away from the processing of basic materials and toward fabrication and finishing activities.

While it is widely recognized that some basic industries like steel are in great trouble, the cause of this trouble is widely attributed to the inability of our basic industries to compete in world markets, owing to the immediate problem of the overvalued dollar and the longer term problem of high-cost American labor. However, what is not well appreciated is that there is strong evidence of saturation, not in production, but in the demand for basic materials in the United States. And this structural shift implies a dramatic slowdown in the growth of demand for both primary energy and electricity by the industrial sector because the subsectors of industry growing most rapidly are not very energy or electricity-intensive.

My colleagues have examined in some detail the nature and reasons for the industrial structural changes that have taken place to date and the prospects for future growth of basic materials. I request that a report of our findings be attached to my written testimony.

Senator EVANS. Without objection.

Dr. WILLIAMS. And here I will just highlight some of the major results.

One of our most significant findings is that for a wide range of basic materials, per capita apparent consumption—that's production, plus imports, minus exports, with adjustments for stock changes—peaked in the 1970's, and this is shown in figure 4 where I've measured basic materials in terms of kilograms, so that consumption is in kilograms per capita.

One factor contributing to what appears to be an approaching saturation in the demand for basic materials is the substitution of new materials for old. Clearly, this is not the dominant factor, as this figure shows, that the peaking occurred not just for traditional materials like steel, cement, and paper, but also for more modern materials like aluminum, ethylene, chlorine, ammonia, et cetera.

Materials, in addition, are being used more efficiently. For example, by the development of high strength to weight ratio materials and more durable materials as a response to increased costs—especially energy costs—and as a response to competitive pressures from potential substitutes.

And especially important is the shift at high levels of affluence to less material-intensive products. These changing consumer preferences are leading to saturation in markets for bulk materials; for example, sheet steels for aluminums and major household appliances, and growth in new markets for value-added intensive products. We are seeing the emergency of a society where growth is dominated by high technology industries with generally low intensities of material use, such as solid state electronics, computer hardware and software, telecommunications, high value chemicals such as pharmaceuticals, pesticides, herbicides, biogenetics, et cetera.

Case studies that we have performed for all of the materials in figure 4 indicate that the outlook is generally poor for demand growth in bulk markets, though continued expansion can be expected for value added intensive products that involve only modest materials inputs.

What is happening to basic materials in aggregate in the U.S. economy is illustrated in figure 5, attached to my testimony, which shows the trend since 1960 of aggregate indices of materials consumption and production as well, using fixed energy intensities as weights. This figure shows that aggregate materials use in production per dollar have been declining since the early 1970's, and similarly, consumption and production per capita appear to have been roughly constant in the 1970's except for the prominent troughs in 1975 and 1982.

Our analysis indicates that the most likely course for the future is that aggregate materials consumption and production per capita in the United States will not increase between now and the year 2000. To understand the implications of this outlook for energy demand and electricity demand, it is necessary to make some judgments about the likely trend and energy intensity of industry in this period.

We have shown, on the basis of price considerations and case studies for specific industries, that it is reasonable to expect that in the future, the energy intensity of industry will decline at a rate of between 1 and 2 percent per year in the period to the end of the century; the latter rate, more rapid rate, being the continuing of the average rate of the last 11 years.

These estimates of the future trend in basic materials production and industrial energy intensity implies that industrial energy use in 2000 will not increase, or actually decline slightly, if GNP grows at an average rate of 2½ percent per year in this time period. This trend in overall energy use should not be expected to hold for electricity use by industry. Despite its high cost, electricity is a highly desirable energy carrier which offers far more flexibility for carrying out industrial process requirements than solid, liquid, or gaseous fuels. And this attraction, in fact, has led to a continuing share of total industrial energy use by electricity.

If this trend continues—and we expect that it will—electricity use overall in the industrial sector would grow at an average rate of between 1 and 2 percent per year between 1984 and the year 2000. While this is much higher than the zero or negative growth that can be expected for total energy use, it is far less than is what is forecast for the industrial sector, as other forecasters in this hearing have indicated.

Next, I'd like to turn to the—say something about the potential for electricity conservation. The 2.2-fold increase in the inflation-corrected retail price of energy in the United States—that's also a 3.3-fold increase for the industrial sector—since 1972 has set the stage for radical changes in energy end use technology. Because oil glut apathy has led to little reporting of what is happening, I like to refer to the ongoing change as a quiet revolution in energy-efficient technology for energy-using activities throughout the economy.

A listing of some opportunities which have emerged in the last 2 or 3 years for the residential sector give an indication of the significance of this quiet revolution. For example, the most energy-efficient refrigerator/freezer available in the United States is a 17 cubic foot unit with automatic defrost that consumes just half the amount of electricity as the average refrigerator in use. The most efficient central air-conditioner now available uses only 40 percent as much electricity as the average unit in use. The most efficient heat pump water heater now available uses only one-third as much electricity as the typical electric resistance water heater in use. And new compact fluorescent light bulbs which have the same output and color as incandescents, and which can be screwed into incandescent sockets, require only one-fourth as much electricity and last five times as long as incandescents.

The potential impact on energy supply requirements of shifting to such more efficient units is very great. Table 2 summarizes the results of a study we have done exploring what would happen to energy demand in single family housing by the year 2000 if new energy-using systems for the home having energy performance characteristics equivalent to the most efficient commercially available in 1982 were introduced at the rates of equipment turnover in growth.

This table shows that aggregate energy use in 2000 would be reduced by nearly a third, relative to the 1980 level; but, as in the industrial sector, the electricity share of residential energy use would increase with this projection and electricity use would decline by a lesser 20 percent. But this reduction for single family housing alone is equivalent to an output of about 22 large central station powerplants.

The more energy efficient path would not only obviate the need for new powerplant construction, but it would save consumers a great deal of money because the extra first cost of typical more efficient model is paid back in reduced energy bills long before it wears out, a source of major direct savings; and, in addition, to the extent that aggregate purchases of efficient units by consumers enable the deferral of new powerplant construction, consumers would also benefit from lower utility rates.

Now, I'd like to turn to the third part of my testimony which deals with uncertainty in planning low energy futures. The future is easy to understand and predict only if it can be expected to be more or less like the past. And I think that the committee will appreciate from the diversity of the testimony they have heard in this hearing, that for utility planners today, the only certainty is that the future will not be like the past.

The prospect of major but incompletely understood structural shifts away from energy-intensive economic activities makes multibillion dollar supply expansion planning for the utility industry an even riskier undertaking than it has been in the troubled decade the industry has just struggled through. And the investment opportunities and conservation add still more elements of uncertainty to the utility planning process.

Despite the attractive economics of energy efficiency improvements, consumers, because of a variety of institutional obstacles, are not making investments in energy efficiency at the extent that can be cost-justified. It is widely recognized that because of conservation market shortcomings, some kinds of utility programs are probably needed to promote investments in energy efficiency. It is also widely recognized, however, that one cannot know in advance the efficacy of alternative utility programs in realizing conservation goals.

The problem is not simply one of finding out how to best motivate consumers; it is also often difficult to predict the energy savings that will result from successful marketing efforts.

The inherent uncertainties regarding the outcome of conservation efforts has led to the perception that conservation is a very risky strategy for electric utility planning. The conventional wisdom, in fact, is that the best way to deal with uncertainty regarding future electricity demand growth is to build enough generating capacity to ensure that the utility is not caught short, should the highest plausible demand forecast be realized.

But while overbuilding would seem to provide a hedge against uncertainty, it does not always generate the certainty of outcome its advocates claim, as the large number of cancellations of partially completed plants, due to financial and other pressures, shows clearly. Moreover, overbuilding is a very costly insurance policy. It destroys the utility incentive to promote conservation measures that would be less costly to the economy, and it contributes to the problem of capital scarcity which is likely to remain with us for years as the Nation struggles to reduce the budget deficit.

Now, I'd like to turn to the third part which involves emphasizing short lead time power sources as an alternative insurance policy.

An overbuilding insurance policy is motivated by the belief that utility expansion must be based predominantly on long lead time central station powerplants which can produce power at less cost than small plants characterized by short lead times. But this is no longer the case. The quiet revolution in energy efficient technology is also bringing to market a number of short lead time technologies that are competitive with conventional powerplants.

In my written testimony I discuss two options—cogeneration and steam injected gas turbines for central station power generation. I will not in my verbal testimony talk about cogeneration, much of which is well-understood, and I will instead focus on steam injection gas turbines which is quite a new idea and is worth focusing on.

The steam injected gas turbines are today under development for central station power applications at the General Electric Co. in a project being carried out for the Pacific Gas and Electric Co. The basic idea with this technology for central station power applications is to operate gas turbine exhaust heat recovery boiler system in a way such that the high pressure steam generated from the boiler is injected back into the turbine combuster and directed through the turbine. The motivation is to produce more electricity with the same turbine and to do so at higher efficiency.

What the developmental work shows is quite remarkable. The simple cycle G.E. gas turbine, when modified for steam injection and intercooling, which is a technology which is already commercial, will have its output increased from 33 megawatts to 108 megawatts, and the efficiency of electric power generation increased from 33 to 50 percent. The installed capital cost in both cases is expected to be the same—about $500 per kilowatt—less than half the capital cost of new coal plants and only about a quarter of the capital cost of new nuclear plants, assuming no cost overruns.

This high efficiency, short lead time, low capital cost technology, also offers environmental advantages. It uses clean, low sulfur fuels and steam injection as one of the strategies that is already used for NO_x control. It also offers fuel flexibility. The system design strategy of interest to PG&E is one involving natural gas as the initial fuel with a switch later on to an alternative fuel such as synthetic gas from coal, should that prove to be necessary.

The system is so efficient and so low in capital cost, however, that a switch to alternative fuels can be delayed for a long time. In the appendix to my testimony, I have estimated for each of the lower 48 States the levelized busbar cost for power generation using this system, assuming operation beginning in 1990 and 3 percent annual escalation in the natural gas price during the expected life of the system.

The system, as my calculations show, is estimated to be able to produce electricity at lower cost than either coal or nuclear power using DOE cost estimates in most States; that is, lower cost at the busbars. In fact, in most areas that already use gas to generate electricity and steam plants, it would be worthwhile to scrap the existing steam plants and to replace these plants with the steam injected gas turbine plants. And, in fact, if one were to use all the natural gas that is now committed to steam power generation, the incremental amount of power that could be produced is equivalent to the output of 31 nuclear powerplants.

The development of this technology is taking place in two stages. In the first stage, an existing G.E. turbine at the Simpson Paper Co. near Anderson in northern California will have its turbine modified to inject steam to produce more power. With this modification, the gas turbine will produce electricity at an efficiency of 40 percent. This work will be done this year. An agreement to sell the electricity to PG&E has been reached.

The second stage of development requires more significant hardware changes, using a larger power turbine, and changing a few compressor stages to add an intercooler. It is estimated by General Electric that, with adequate R&D support, G.E. could have the advanced design ready for commercial sales in 1988.

The technology clearly represents a major breakthrough for utility planning. It could obviate the need to base multi-billion dollar investment decisions on long term utility load forecasts which simply cannot be made reliably.

In conclusion, I think that policymakers should strive to provide incentives for utilities to pursue the least costly mix of investments in new energy supply and end use efficiency for meeting energy service requirements consistent with environmental and national security objectives. For a long time to come, this least cost energy strategy will lead to much lower electricity demand growth than is presently being planned for.

Cogeneration and central station power, based on steam injected gas turbines are existence proofs that there are alternatives to overbuilding costly large new central station plants for coping with the problem of uncertainty inherent in planning for low energy futures.

I show in table 5 some generating capacity which could be called upon by the 1990's, if needed, without ordering more coal or nuclear plants. The list does not exhaust the possibility, but merely shows how far one can go with planned construction and the options I have discussed explicitly in my testimony. The capacity shown is equivalent in total to nearly half the total U.S. electricity production at present, or the output of 180 large coal and nuclear plants.

This capacity could be adequate to provide for growth at an annual rate of 2.2 percent in demand to the year 2000. Small scale cogeneration, which is not included here, and greater use of steam injected gas turbines beyond what could be provided with the existing gas supply now being committed to power generation, could provide for even greater growth if needed.

My professional judgment is that I don't think even 2.2 percent annual growth will be sustained for this period, but with emphasis on technologies like the steam injected gas turbine, planners would not have to base multi-billion dollar investment decisions on my judgments or the judgments of any other energy demand experts.

[The prepared statement of Dr. Williams follows:]

Invited Testimony

by

Robert H. Williams
Senior Research Scientist
Center for Energy and Environmental Studies
Princeton University
Princeton, New Jersey 08544

(609) 452-5448

at the

Oversight Hearing

On the Potential for Serious Regional Shortages of
Electric Power in the United States by the Early 1990's

before the

Committee on Energy and Natural Resources
United States Senate
Washington, DC

July 25, 1985
(Revised, July 30, 1985)

In my testimony I shall argue that utility planners should (a) plan for slower electricity demand growth than what is projected in most forecasts, because of structural shifts in the economy to less energy-intensive activities and because of the economic benefits to the economy of pursuing opportunities for more efficient energy use and (b) take advantage of new cost-effective opportunities for short lead-time power generation that could be exploited if electricity demand should grow faster than planned. Specifically, I shall make four points:

- An important development inadequately dealt with in most energy demand forecasts is the ongoing structural shift in the U.S. industrial sector, away from the processing of basic materials and toward less energy-intensive fabrication and finishing. This shift implies that industrial energy use overall will probably not grow between now and the end of the century and may well decline, and that industrial electricity demand will grow at an average rate of only 1 to 2% per year.
- The opportunities for energy conservation with more efficient electricity-using devices in all electricity-consuming sectors are vast and continually expanding. Capturing these opportunities could slow electricity demand growth almost to a halt.
- Despite the evidence for less energy-intensive future economic growth and the promise of conservation, the conventional wisdom has been that it is better to overbuild generating capacity -- to be prepared to deal with the prospect, however remote, of unforeseeable needs for power, and not to be dependent on hoped-for but uncertain energy savings, which may or may not be realized, even with promotional utility programs.
- Overbuilding is a very costly "insurance policy," however, which is no longer necessary, because there are cost-effective supply alternatives which can be brought on line quickly, obviating the need to rely on supply technologies with lead times of a decade or more.

In what follows I will deal with each of these issues in turn.

ONGOING STRUCTURAL CHANGE IN THE INDUSTRIAL SECTOR

The long-established trend away from goods production and toward services production is widely recognized. What is not so well known is the pervasive shift underway within industry, away from the processing of basic materials and toward fabrication and finishing activities.

While it is widely recognized that some basic industries like steel are in great trouble, the cause of this trouble is widely attributed to the inability of our basic industries to compete in world markets, owing to the immediate problem of the overvalued dollar and the longer term problem of relatively high-cost American labor. What is not well appreciated is that there is also strong evidence of saturation in the demand for basic materials in the US (and in other industrialized market economies as well). This structural shift implies a dramatic slowdown in the growth of demand for both final energy and electricity by the industrial sector, because the subsectors of industry growing most rapidly are not very energy- or electricity-intensive. Figure 1 shows that the basic materials processing industries (petroleum refining; primary metals; chemicals; paper; stone, clay and glass; and the food processing industries), which account for only 1/3 of manufacturing value-added, consume 14 times as much final energy per dollar of value-added, on average as "other manufacturing," which involves largely the fabrication and finishing of basic materials. Similarly, Figure 2 shows that the basic materials processing industries use about 5 times as much electricity per dollar as the rest of manufacturing.

My colleagues and I have examined in some detail the nature and reasons for the industrial structural changes that have taken place to date and the prospects for future growth of basic materials. I request that a report of our findings (Marc Ross, Eric D. Larson, and Robert H. Williams, July 1985) be attached to my written testimony. Here I will just highlight the major results.

The declining importance of basic materials in the US economy can be understood in the context of the changing needs of society as the economy evolves. In the early stages of the history of a material's use, consumption tends to grow very rapidly -- typically much more rapidly than GNP. This stage of rapid growth is conducive to cost-cutting innovations that spur continued rapid growth. But after a while, demand for the material per unit of GNP peaks and goes into decline, as the markets for the material mature. In the final stage of a material's life-cycle, demand for the material ceases to grow on a per capita basis. This classic material use cycle is well-illustrated by the long term history of steel use in the US (see Figure 3). The consumption of steel per dollar of real GNP has followed a bell-shaped curve which peaked about 1920 and has now declined to the level that characterized the 1880s, about 1/3 the peak value. The consumption of steel per capita has followd an S-shaped curve; per capita consumption grew by nearly a factor of ten from the 1880s to the 1940s and has been almost constant since then. (Actually it may now be entering a long-term decline.)

Most energy-intensive materials in the US have followed a similar pattern. In fact, for a wide range of basic materials, per capita apparent consumption (production plus net imports, adjusted for stock changes) peaked in the 1970s, as shown in Figure 4.

One factor contributing to what appears to an approaching saturation in the demand for basic materials is the substitution of new materials for old. But clearly this is not the dominant factor, as this peaking has occurred not just for traditional materials (e.g., steel, cement, paper) but for more modern materials (e.g., aluminum, ethelyne, chorine, ammonia) as well. Materials are also being used more efficiently (e.g., via the development of high strength-to-weight ratio materials and more durable materials), as a response to increased costs (especially energy costs) and as a response to competitive pressures from potential substitutes. Especially important is the shift, at high levels of affluence, to less materials-intensive products. These changing consumer preferences are leading to saturation in markets for bulk materials (e.g., sheet steel for automobiles and major household appliances), and growth in new markets for value-added-intensive products. We are seeing the emergence of a society where growth is dominated by high-technology industries with generally low intensities of materials use, such as solid state electronics, computer hardware and software, telecommunications, high value chemicals (pharmaceuticals, pesticides and herbicides, etc.), and biogenetics. Case studies for all the materials shown in Figure 4 indicate that the outlook is generally poor for demand growth in bulk markets, though continued expansion can be expected for value-added intensive products that involve only modest materials inputs (Eric D. Larson, Robert H. Williams, and Drew Bienkowski, 1984).

What is happening to basic materials in aggregate in the US economy is illustrated in Figure 5, which shows the trend, 1960-1984, of aggregate indices of both materials consumption and materials production, using fixed energy-intensities as weights. Tonnages of steel, aluminum, cement, paper, petroleum refinery products, and a combination of 20 large volume industrial chemicals, weighted by energy-of-manufacture intensities from the late 1970s, were chosen to represent the energy-intensive materials for this graph. This figure shows that, as for the 7 materials highlighted in Figure 4 and for the same reasons, aggregate materials use and production per dollar have been declining since the early 1970s. Similarly, consumption and production per capita appear (except for the prominent troughs in 1975 and 1982) to have been roughly constant in the 1970s.

The plateauing of materials use per capita has been a major contributor to the reduction in industrial energy use per dollar of GNP in recent years. Between 1973 and 1984 industrial energy use per dollar of real GNP declined at an average rate of 3.6% per year, of which the reduced role of materials production contributed almost half, or 1.6% per year (Marc Ross, Eric D. Larson, and Robert H. Williams, July 1985).

In the appended report it is shown that the implications of ongoing structural changes are that aggregate materials consumption and production per capita in the US are not likely to increase between now and the year 2000.

To understand the implications of this outlook for energy demand it is necessary to make some judgments about the likely trend in the energy intensity of industry in this period. Since the first oil shock the energy intensity of industry has been reduced 20%, an improvement which must be regarded as modest in relation to the 3.2-fold increase in the inflation-corrected price of energy in the period 1970-1982 (Energy Information Administration, April 1985). Investments to achieve energy conservation are continuing to occur even where prices are no longer rising. This trend can be expected to continue, since most of the cost-effective opportunities to reduce energy intensity which require significant investments remain to be exploited.

In looking to the future it is reasonable, in light of high energy prices and case studies for specific industries (Marc Ross, 1985; William Larsen and Marc Ross, 1985) to expect that in the future the energy intensity of industry will decline at a rate in the range of 1 to 2 percent per year -- the latter being a continuation of the average rate for the period 1973-84.

These estimates of the future trend in basic materials production and industrial energy intensity imply that industrial energy use will be 0.86 to 1.01 times as large in 2000 as in 1984, if GNP grows at an average annual rate of 2.5% per year to the end of the century (Marc H. Ross, Eric D. Larson, and Robert H. Williams, 1985).

This trend for energy overall should not be expected to hold for electricity use by industry. Despite its high cost, electricity is a highly desirable energy carrier which offers far more flexibility for carrying out industrial process requirements than solid, liquid, or gaseous fuels (Phil Schmidt, 1984), an attraction that has led to an annual increase in electricity's share of total industrial energy use of about 1/4 percent per year, on average, since 1973 (see Table 1). If this trend contines, industrial electricity use would account for 14% of primary industrial energy use in 2000, up from 10% in 1984, and electricity use overall would grow at an annual rate of between 1 and 2 percent per year.

While this is much higher than the zero or negative growth that can be expected for total energy use, it is far less than what is typically forecast for future industrial electricity use. For example, it is far less than the 2.9 percent average growth rate forecast last year by Electrical World, the trade journal of the electric utility industry (35th Annual Electric Utility Industry Forecast, September 1984). The difference by the year 2000 is equivalent to the output of 31 to 63 large large (1000 MW) nuclear or coal fired power plants.

THE POTENTIAL FOR ELECTRICITY CONSERVATION

The 2.2-fold increase in the inflation-corrected retail price of energy in the US since 1972 has set the stage for radical change in energy end-use technology. Because oil-glut apathy has led to little reporting of what is happening, I like to refer tc the the ongoing change as a "quiet revolution in energy-efficient technology" for energy-using activities throughout the economy.

A listing of some opportunities which have emerged in the last 2 or 3 years for the residential sector gives an indication of the significance of this quiet revolution (American Council for an Energy-Efficient Economy, June 1985):

- The most efficient refrigerator/freezer available in the US in 1985 is a 17.2 cubic foot unit with automatic defrost consuming just 750 kWh per year, compared to about 1500 kWh for the typical model in use.
- The most efficient central air conditioner now available uses only about 40% as much electricity as the average unit in use.
- The most efficient heat pump water heater now available uses only one third as much electricity as the typical electric resistance water heater in use.
- New compact fluorescent lightbulbs, which have the same light output and color as incandescents and which can be screwed into incandescent sockets, require only 1/4 as much electricity and last 5 times as long as incandescents.

The potential impact on energy supply requirements of shifting to such more efficient units is substantial. If the average refrigerator/freezer in use had the energy performance of the most efficient one available, for example, the result would be a freeing up of electricity supplies equivalent to the output of 12 large (1000 MW) coal or nuclear power plants. Table 2 summarizes the results of a study (Robert H. Williams, Gautam S. Dutt, and Howard S. Geller, 1983) exploring what would happen to energy demand in single family housing by the year 2000 if new energy-using systems for the home having energy performance characteristics equivalent to the most efficient commercially available in 1982 were introduced at the rates of equipment turnover and growth, for a single family housing stock that increases from 56 million in 1980 to 70 million in 2000, and for the major increases in appliance saturation levels indicated in Table 3. Table 2 shows that aggregate energy use in 2000 would be reduced by nearly 1/3, relative to the 1980 level. As in the industrial case discussed earlier, electricity's share of energy would increase in this projection, and electricity use would decline by a lesser 20%. The electricity savings for single family housing, relative to 1980 electricity use, is equivalent to the output of 22 large (1000 MW) coal or nuclear power plants.

In contrast to the 1% per year average rate of decline in electricity use for this scenario, Electrical World forecast last year an average growth rate of 2.3% per year for residential electricity demand, 1980-2000 (35th Annual Electric Utility Industry Forecast, September 1984).

The more energy-efficient path would not only obviate the need for new power plant construction, but it would also save consumers considerable money. The extra first cost of the typical more energy-efficient model is paid back in reduced energy bills long before it wears out, a source of major direct savings. In addition, to the extent that aggregate purchases of efficient units by consumers enable the deferral of new power plant construction, consumers would also benefit from lower utility rates. That this indirect savings could be substantial is indicated by the Electrical World projection that the average residential rate would increase (in 1984 dollars) from 7.4 cents per kWh in 1984 to 10.6 cents per kWh in 2000 -- an increase (amounting to $340 per household per year, for the level of electricity use projected by Electrical World for 2000) needed to pay for the costly new power plants that would have to be built to realize the Electrical World scenario.

UNCERTAINTY IN PLANNING LOW ENERGY FUTURES

The future is easy to understand and predict only if it can be expected to be more or less like the past. Unfortunately for utility planners today, the only certainty is that the future will not be like the past. The prospect of major, but incompletely understood, structural shifts away from energy-intensive economic activities makes mult-billion dollar supply expansion planning for the utility industry an even riskier undertaking than it has been in the troubled decade the industry has just struggled through.

The investment opportunities in conservation add still more elements of uncertainty to the utility planning process. Despite the rapid growth in conservation investment opportunities and the attractive life-cycle costs of many energy-efficiency improvements, consumers, because of various institutional obstacles, are not making investments in energy efficiency to the extent that can be cost-justified (Robert H. Williams, Gautam S. Dutt, and Howard S. Geller, 1983). It is widely recognized that because of "conservation market shortcomings" some kinds of utility programs are needed to promote investments in energy efficiency.

It is also widely recognized, however, that one cannot know in advance the efficacy of alternative utility programs in realizing conservation goals. The problem is not simply one of finding out how best to motivate consumers. It is also often difficult to predict the energy savings that will result from successful marketing efforts. What is needed is flexible planning -- involving program monitoring, scorekeeping, and feedback, and continual improvement in conservation programs in light of learning what works and what doesn't.

The inherent uncertainties regarding the outcome of conservation efforts has led to the perception that conservation is a very risky strategy for electric utility planning. The conventional wisdom, in fact, is that the best way to deal with uncertainty regarding future electrical demand growth is to build enough generating capacity to ensure that the utility is not caught short, should the highest plausible demand forecasts be realized (E.G. Cazalet, C.E. Clark, and T.W. Keelin, 1978).

While overbuilding would seem to provide a hedge against uncertainty, it does not always generate the certainty of outcome its advocates claim, as the large number of cancellations of partially completed power plants due to financial and other pressures shows clearly. Moreover, overbuilding is a very costly "insurance policy." It destroys the utility incentive to promote conservation measures that would be less costly to the economy, and it contributes to the problem of capital scarcity which is likely to remain with us for many years, as the Nation struggles to reduce the budget deficit.

EMPHASIZING SHORT LEAD-TIME POWER SOURCES AS AN ALTERNATIVE INSURANCE POLICY

An "overbuilding insurance policy" is motivated by the belief that utility expansion must be based predominantly on long lead time central station power plants which can produce power at less cost than small plants characterized by short lead times. But this is no longer the case.

The quiet revolution in energy-efficient technology is also bringing to market a number of short lead-time technologies that are competitive with the conventional power plants. Here I will discuss two especially significant options: cogeneration and steam-injected gas turbines for central station power generation.

The Outlook for Cogeneration: After its long term decline and virtual demise as a source of electric power in the US, cogeneration has, since the Supreme Court decisions of 1982 and 1983 upholding the PURPA rules, risen from the ashes to become a booming US industry. Some 7 GW (e) of new cogeneration capacity were added in 1982-83 (Glenn H. Lovin, May/June 1984) and another 7 GW (e) in 1984 (Cogeneration and Small Power Applications, May/June 1985). The cogeneration capacity added in 1984 was nearly as large as the 9.2 GW (e) of combined nuclear and fossil-fuel based steam central station generating capacity added then (1985 Annual Statistical Report, April 1985).

The total new cogeneration potential estimated by the US DOE in the period to the year 2000 is some 260 TWh per year (see Table 4), equivalent to the output of some 46 large (1000 MW) coal or nuclear power plants. I believe this estimate will prove to be low, for several reasons.

First, it deals only with relatively large scale industrial cogeneration. The market for packaged systems in small sizes (ranging from under a megawatt to several megawatts) for schools, shopping centers, hospitals, office and appartment complexes could potentially be comparable to or even larger than the market for "big" cogeneration. One estimate of the economically feasible market for "small" cogeneration is some $67 billion between now and 2000 (David G. Wallace, July/August 1985).

Second, the DOE analysis is based entirely on technology commercially available at the time the report was written and is thus already obsolete. For example, the recent commercial availability of steam-injected gas turbines (Eric D. Larson and Robert H. Williams, June 1985) makes it economically attractive to use gas turbines in applications characterized by variable steam loads, thus greatly expanding the market potential for gas turbine/waste heat recovery boiler cogeneration systems, which have high thermodynamic efficiency and electricity production potential (Robert H. Williams, 1978) and low capital cost (see Figure 6) compared to other cogeneration technologies. Hitherto, gas turbine-based cogeneration has been restricted largely to to applications characterized by steady steam loads. In the Appendix attached to my testimony this technology is described, and it is shown that even at very small turbine sizes (a few megawatts) the produced electricity would be less costly than electricity purchased from the utility in many parts of the country.

Finally, the proof is in the pudding. For the state of California the DOE study estimated a total potential new cogeneration capacity of 3.9 GW for the period 1980 to 2000. But as shown in Table 4 the three major utilities in the state of California have already signed contracts for cogeneration capacity totalling about 6 GW; moreover, the total cogeneration capacity in California in operation, under contract but not yet operational, and under active discussion is some 9 GW (California PUC Decision 8504075, April 17, 1985). Indeed the state of California now faces a glut supply of potential cogeneration capacity!

Steam-Injected Gas Turbines for Central Station Power Generation: Despite the many financial planning problems posed by conventional central station power plants and the promise of cogeneration technology, utility planners should not assume that the era of central station power is coming to an end. In some parts of the country the cogeneration potential is small, because the industrial process steam loads needed to support cogeneration are small. Moreover, there are promising new developments in central station generating technology -- one of which I shall now briefly discuss.

The steam-injected gas turbines that have recently been commercialized for cogeneration purposes are also under development for central station power applications, at the General Electric Company, in a project being carried out for the Pacific Gas and Electric Company (PG & E Engineering Department, July 1984).

The basic idea with this technology for central station power applications is to operate a gas turbine/exhaust heat recovery boiler system in a way such that the high pressure steam generated in the boiler is injected back into the turbine combustor and directed through the turbine. The motivation is to produce more electricity with the same turbine, and to do so at higher efficiency.

What the development work shows is quite remarkable. A simple cycle GE gas turbine, when modified for steam injection and intercooling,* will have its output increased from 33 MW to 108 MW and the efficiency of electric power generation increased from 33% to 50% (based on higher heating value). The installed capital cost in both cases is expected to be about $500 per kW -- less than half the capital cost of new coal plants and only about a quarter of the capital cost of a new nuclear plant (assuming no overruns).

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*Intercooling is a technology that is already commercial.

This high-efficiency, short lead-time, low capital-cost technology also offers enviromental advantages: it uses clean, low sulfur fuels, and steam injection is one of the strategies that is already used for NOx control. And it offers fuel flexibility. The system design strategy of interest to PG & E is one involving natural gas as the initial fuel, with a switch later to an alternative fuel such as synthetic gas from coal, should that be necessary. The system is so efficient and so low in capital cost, however, that a switch to alternative fuels can be delayed a long time.

In the appendix I have estimated for each of the lower 48 states the levelized busbar cost for power generation using this system, assuming operation beginning in 1990 and 3% annual real escalation in the natural gas price during the expected 20 year system life. The system is estimated to be able to produce electricity at lower cost than either coal or nuclear power (for which I have assumed US DOE cost estimates) in most states. In addition, the economics are so favorable that in most areas where gas is already being used to produce electricity in steam-electric power plants, it would be worthwhile to replace the inefficient, existing plants with steam-injected gas turbines.*

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* It would be worthwhile to scrap the existing plant (regardless of how much useful plant life is left) and replace it with a steam-injected gas turbine if the fuel cost of operating the existing plant were greater than the total cost (including capital cost) of the new steam-injected gas turbine. The average heat rate for natural gas-fired thermal plants in the US was 10,800 BTU/kWh in 1984 (Energy Information Administration, March 1985). Table A - 3 in the appendix shows that the total cost of power from a steam-injected gas turbine for central station power generation is 15.4 + 6.8 x P mills per kWh, where P is the fuel price in dollars per million BTU. Thus it would be worthwhile to scrap the existing plant if

$$10.8 \times P > 15.4 + 6.8 \times P, \text{ or } P > \$3.85 \text{ per millon BTU.}$$

For comparison, the average price being paid by electric utilities for natural gas in the US in 1985 is about $4.20 per million BTU.

The favorable economics of steam-injected gas turbines relative to existing steam-electric power generation with natural gas suggests an important large initial market for these systems, despite the excess capacity problem inhibiting new investments in most areas. Replacing the 1984 natural gas-based electricity production of 297 TWh with steam injected gas turbines would require over 400 plants of 100 MW capacity. These plants would be able to produce the same amount of electricity with 1.2 Quads less gas per year -- freeing up for other purposes an amount of gas equivalent to more than half a million barrels of oil per day. Alternatively, the same amount of gas now being used for electric power generation, if used in steam-injected gas turbines, could produce 174 TWh more electricity each year -- equivalent to the output of 31 large (1000 MW) coal or nuclear power plants.

The ongoing development of steam-injected gas turbines is taking place in two stages. In the first stage an existing GE turbine at the Simpson Paper Company near Anderson in northern California will have its turbine modified to inject steam to produce more power. With this modification the gas turbine will produce electricity at an efficiency of about 40%. This work is expected to be finished this year. An agreement to sell the electricity to PG & E has been reached. The second stage of development requires more significant hardware changes: using a larger power turbine and changing a few compressor stages to add an intercooler. It is estimated that with adequate R&D support GE could have the advanced design ready for commerical sale by 1988 (PG & E Engineering Department, July 1984).

The technology clearly represents a major breakthough for utility planning. It could obviate the need to base multi-billion dollar investment decisions on long range utility load forecasts which simply cannot be made reliably.

CONCLUSION

In conclusion I think that policy-makers should strive to provide incentives for utilities to pursue the least costly mix of investments in new energy supply and end-use efficiency for meeting energy service requirements, consistent with environmental and national security objectives. For a long time to come this least-cost energy strategy will lead to much lower electricity demand growth than is presently being planned for.

Cogeneration and central station power based on steam-injected gas turbines are "existence proofs" that there are competitive alternatives to overbuilding costly large new central station power plants for coping with the problem of uncertainty inherent in planning for low energy futures.

I show in Table 5 some generating capacity which could be called upon by the 1990s if needed, without ordering more large coal or nuclear plants. The list does not exhaust the possibilities, but merely shows how far planners could go with planned construction and the options I have discussed explicitly here. The power sources shown are equivalent in total to nearly half of annual US electricity production at present, or the output of 180 large coal or nuclear power plants. These sources would be adequate to provide for growth at an annual rate of 2.2% to the year 2000. Small-scale cogeneration and greater use of steam-injected gas turbines could provide for even greater growth, if needed. My professional judgment is that I don't think even 2.2% annual demand growth will be realized. But with emphasis on competitive, short lead-time generation technologies like steam-injected gas turbines, planners would not have to base multi-billion dollar investment decisions on my judgment or the judgments of any other energy demand "experts."

Table 1 The Trend Toward Electrification of the Industrial Sector (a)

Year	(1) Industrial Primary Energy Use (quadrillion BTU)	(2) Electricity Purchases (quadrillion BTU)	(3) (2) / (1)
1973	31.538	2.341	0.07423
1974	30.699	2.337	0.07613
1975	28.409	2.346	0.08258
1976	30.245	2.573	0.08507
1977	31.090	2.683	0.08630
1978	31.415	2.761	0.08789
1979	32.625	2.873	0.08806
1980	30.606	2.781	0.09087
1981	29.252	2.817	0.09630
1982	26.140	2.542	0.09725
1983	25.909	2.648	0.10220
1984	27.863	2.868	0.10293

Notes

(a) Source: (Energy Information Administration, June 1985).

(b) Regressing the ratio of electricity purchases to primary energy use versus time yields:

Electricity fraction = - 4.912509 + 0.002528 x year, r = 0.985.

Table 2. Projection of energy use for single-family residences by end use and carrier (EJ per year)

	Electricity		Oil		Natural gas		Other		Total energy use[a]	
	1980	2000	1980	2000	1980	2000	1980	2000	1980	2000
Space heat	0.30	0.22	0.92	0.44	2.83	1.47	0.98	0.56	5.03 (5.74)	2.69 (3.20)
A/C	0.27	0.22	—	—	—	—	—	—	0.27 (0.90)	0.22 (0.74)
Hot water	0.30	0.11	0.12	0.08	0.84	0.38	0.07	0.03	1.33 (2.03)	0.60 (0.86)
Refrigerator/freezer	0.40	0.29	—	—	—	—	—	—	0.40 (1.34)	0.29 (0.96)
Freezer	0.15	0.21	—	—	—	—	—	—	0.15 (0.49)	0.21 (0.70)
Range	0.09	0.11	—	—	0.18	0.13	0.02	0.01	0.32 (0.53)	0.25 (0.51)
Dryer	0.14	0.10	—	—	0.07	0.21	—	—	0.21 (0.54)	0.31 (0.55)
Lights	0.20	0.13	—	—	—	—	—	—	0.20 (0.68)	0.13 (0.42)
Other	0.20	0.24	—	—	0.09	0.11	—	—	0.26 (0.73)	0.35 (0.92)
Total	2.05	1.63	1.04	0.52	4.01	2.30	1.07	0.60	8.2 (13.0)	5.1 (8.9)

[a] Two sets of numbers are shown. The first is the energy consumed at the household. The second (in parentheses) includes losses in the generation, transmission, and distribution.

Table 3

Saturations for energy-intensive household devices (%)

	1980 (actual)	2000 (projected)
Space heat		
Electric		
Resistive	12	9
Heat pump	3	12
Subtotal	15	21
Natural gas	57	57
Oil	15	9
LPG	4	4
Wood	8	8
Other none	1	1
Subtotal	85	79
Hot water		
Electric		
Resistive	33	5
Heat pump	0	34
Subtotal	33	39
Natural gas	55	57
Other/none	12	4
Subtotal	67	61
Air conditioning		
Central	31	46
Room	30	24
	61	70
Refrigerator/freezer		
Frost-free	77	100
Not frost-free	41	0
	118	100
Freezer	54	100
Range		
Electric	59	60
Natural gas	36	36
LPG	5	4
	100	100
Dryer		
Electric	58	43
Natural gas	19	57
	77	100

Table 4 Contracts for Alterative Power in California (in Megawatts) (a)

Source	PG & E	SCE	SG & E	Total
Oil and Gas Based Cogeneration	2494	2696	66	5256
Biomass Power				
Solid Waste Cogeneration	454			
Power Only	809			
Subtotal	1263	773	47	2083
Geothermal	180	730	-	953
Wind	2424	1548	3	3975
Hydro	783	163	2	948
Other	38	272	3	313
TOTALS	7182	6182	121	13,528

Notes

(a) Source: California Public Utility Commission, as of April 17, 1985

Table 5 Potential Electric Power Production From Some New Sources

	Annual Production [TWh per Year]
New Utility Construction Planned for 1984-1992 (a)	
Nuclear (b)	284
Fossil Steam (c)	239
Hydro (d)	26
US DOE Estimate of the Industrial Cogeneration Potential (e)	260
California Commitments for Cogeneration and Small Power Production in Excess of US DOE Cogeneration Estimate (f)	44
Extra Power Obtainable from the 1984 Level of Natural Gas Use by Electric Utilities, if Steam-Electric Plants Were Replaced with Steam-Injected Gas Turbine Power Plants (g)	174
TOTAL	1027

Notes

(a) As projected by the Electrical World, the trade journal of the electric utility journal (35th Annual Electric Utility Industry Forecast, September 1984).

(b) 49.9 GW(e) @ 65% capacity factor.

(c) 41.9 GW(e) @ 65% capacity factor.

(d) 5.85 GW(e) @ 50% capacity factor.

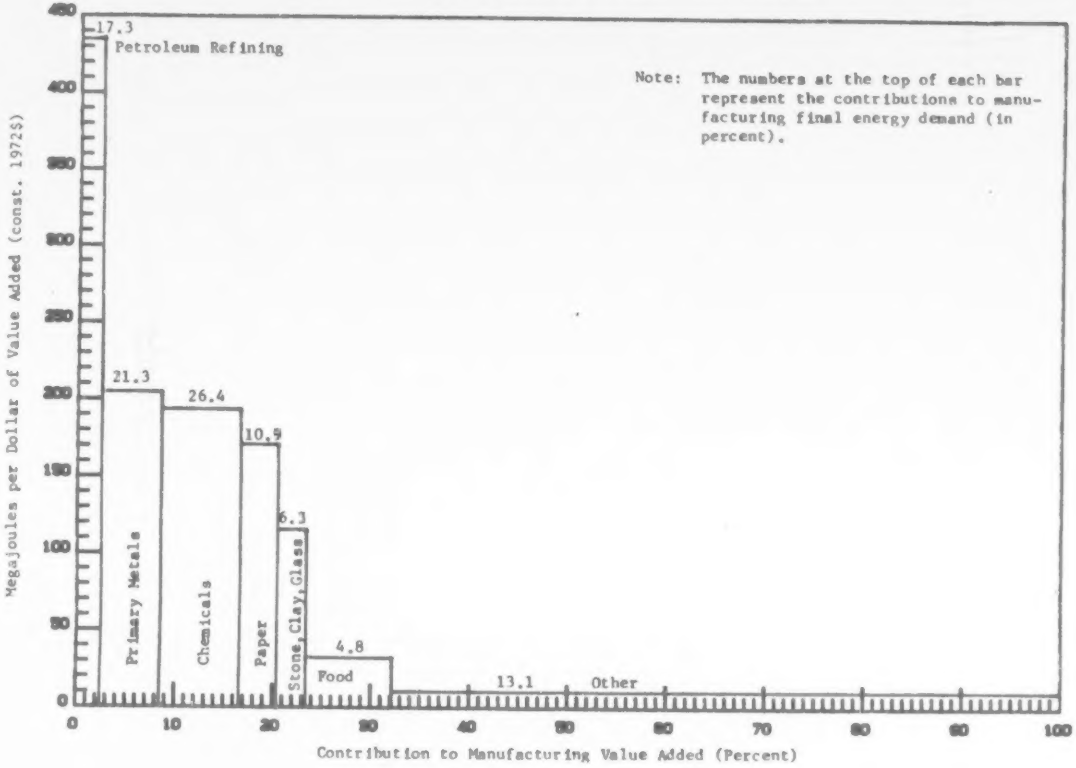
(e) 39.35 GW(e) @ 75% capacity factor. See (Dun & Bradstreet Technical Economic Services and TRW Energy Development Group, August 1984).

(f) Subtracting the 3.944 GW of cogeneration potential estimated for California by the US DOE sponsored study (Dun & Bradstreet Technical Economic Services and TRW Energy Development Group, August 1984) from the total for alternative power shown in Table 4 leaves additional capacity under contract of 4.348 GW for cogeneration, bioenergy, and geothermal; 0.948 GW of hydro; and 4.288 GW of wind and other. The electricity production potential shown here is obtained assuming capacity factors of 75% for cogeneration, bioenergy, geothermal, 50% for hydro, and 30% for wind and other.

(g) In 1984 electric utilities produced 297 Twh of electricity from natural gas @ 10,777 BTU/kWh on average (Energy Information Administration, June 1985). The amount of electricity that could be produced with the same amount of gas by steam-injected gas turbine systems (@ 6800 BTU/kWh) is 471 TWh per year.

Figure 1

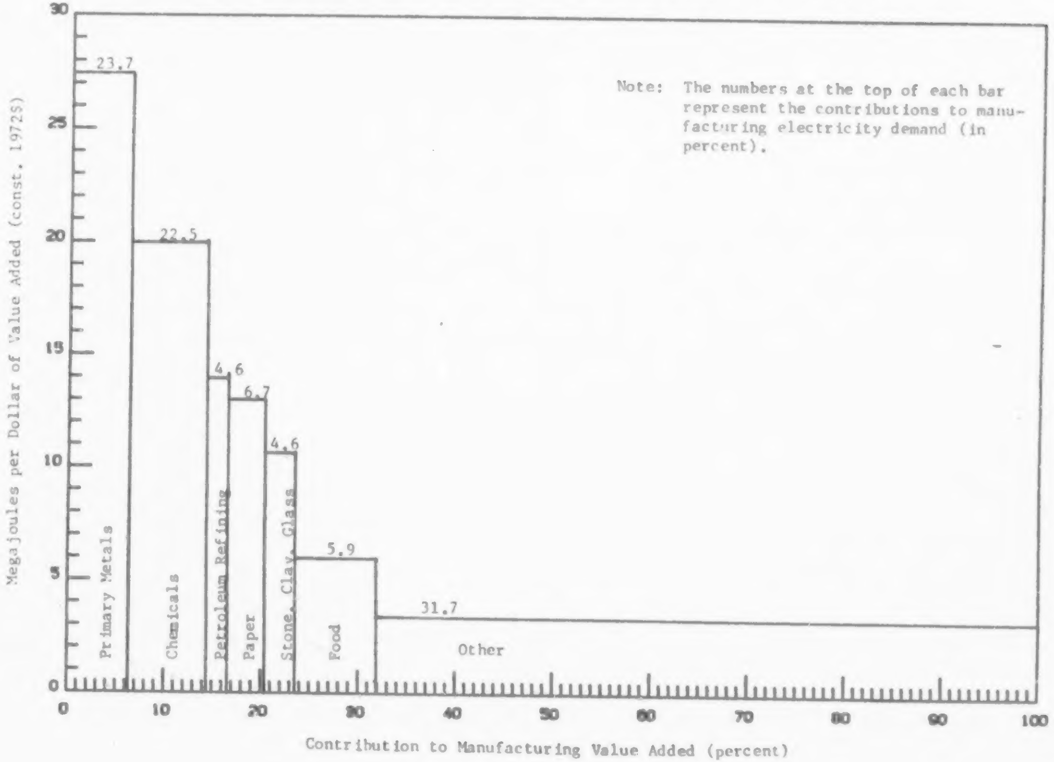
ENERGY INTENSITY VS. MANUFACTURING VALUE ADDED
FOR THE UNITED STATES IN 1978



Note: The numbers at the top of each bar represent the contributions to manufacturing final energy demand (in percent).

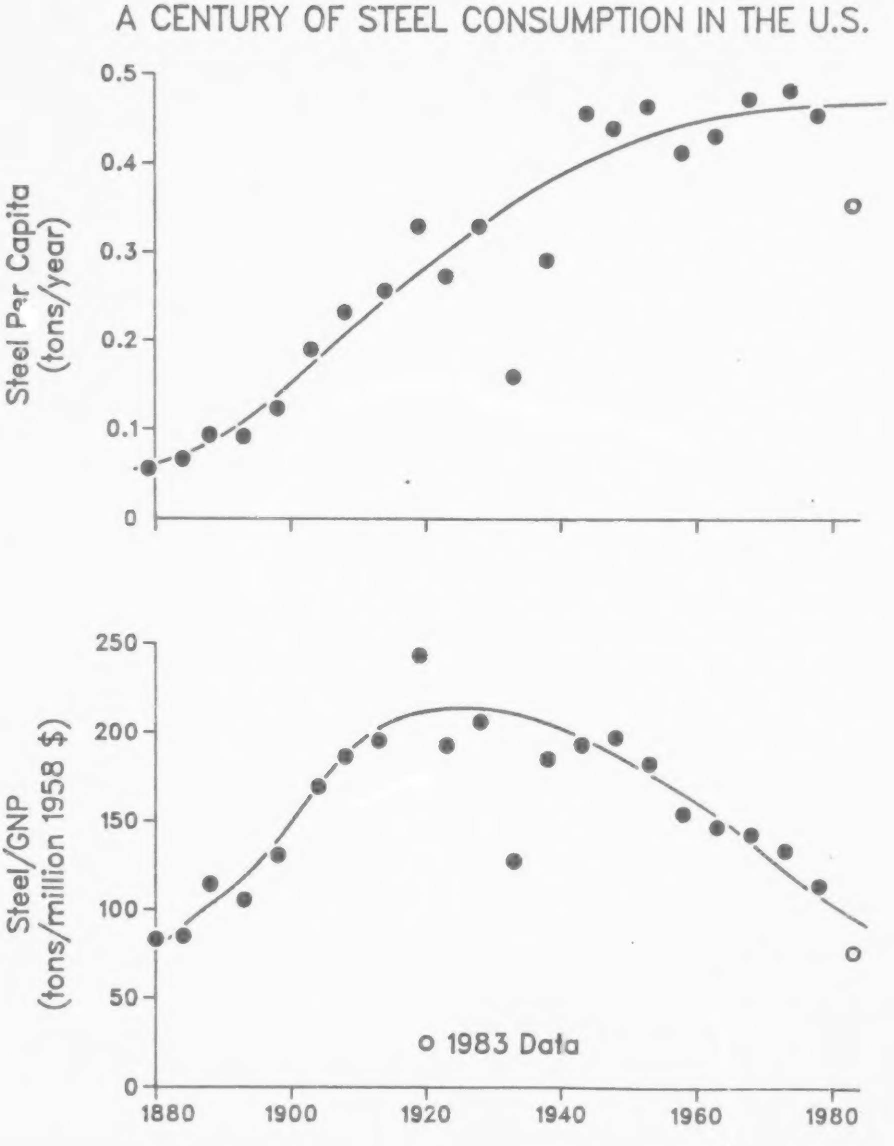
Figure 2

INTENSITY OF ELECTRICITY USE VS. MANUFACTURING VALUE ADDED FOR THE UNITED STATES IN 1978



Note: The numbers at the top of each bar represent the contributions to manufacturing electricity demand (in percent).

Figure 3



Source: (Marc Ross, Eric D. Larson, and Robert H. Williams, July 1985).

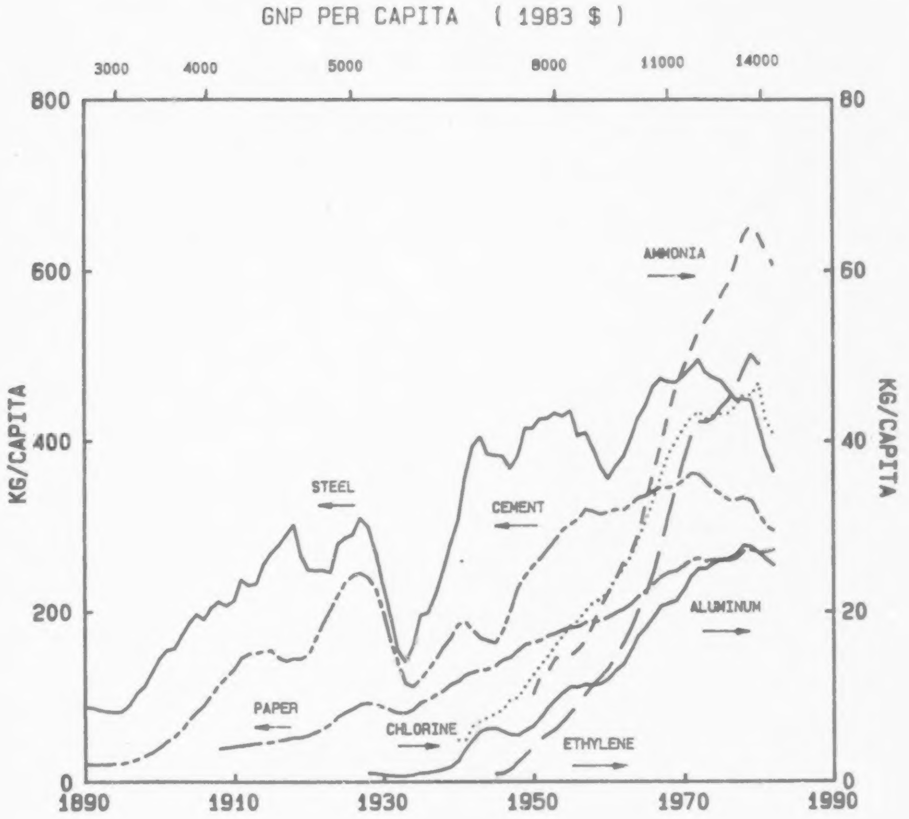


Figure 4

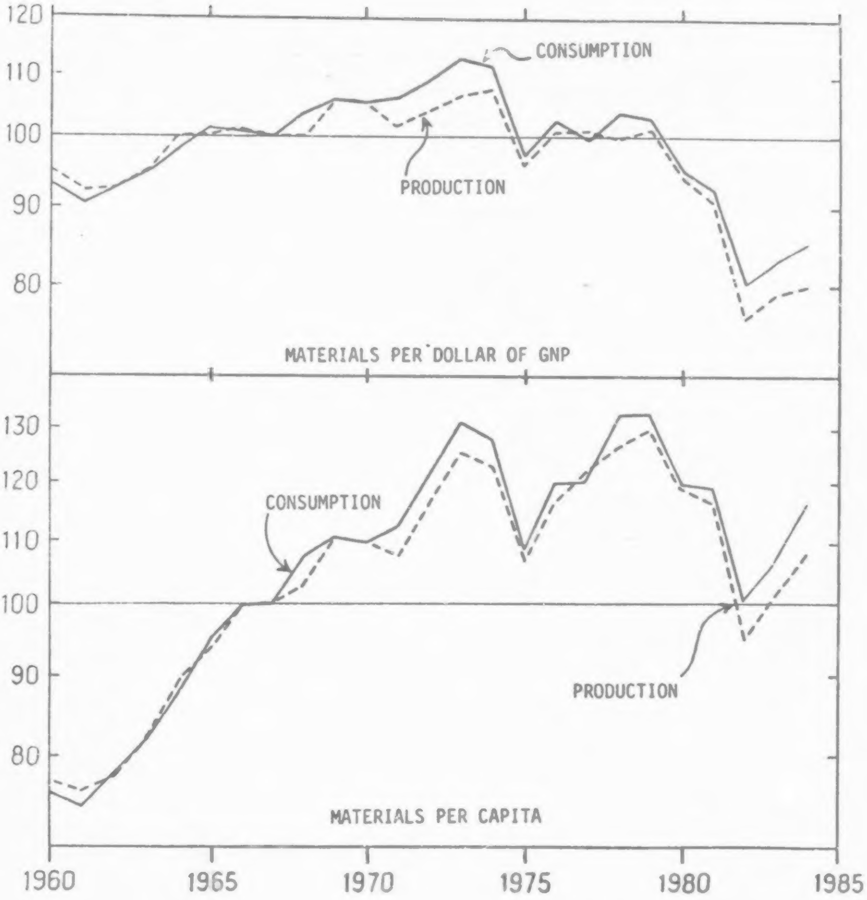
Per Capita Consumption of Selected Basic Materials in the U.S.

Source: (Marc Ross, Eric D. Larson, and Robert H. Williams, July 1985).

Figure 5

MATERIALS IN THE UNITED STATES ECONOMY

1967 : 100



Source: (Marc Ross, Eric D. Larson, and Robert H. Williams, July 1985)

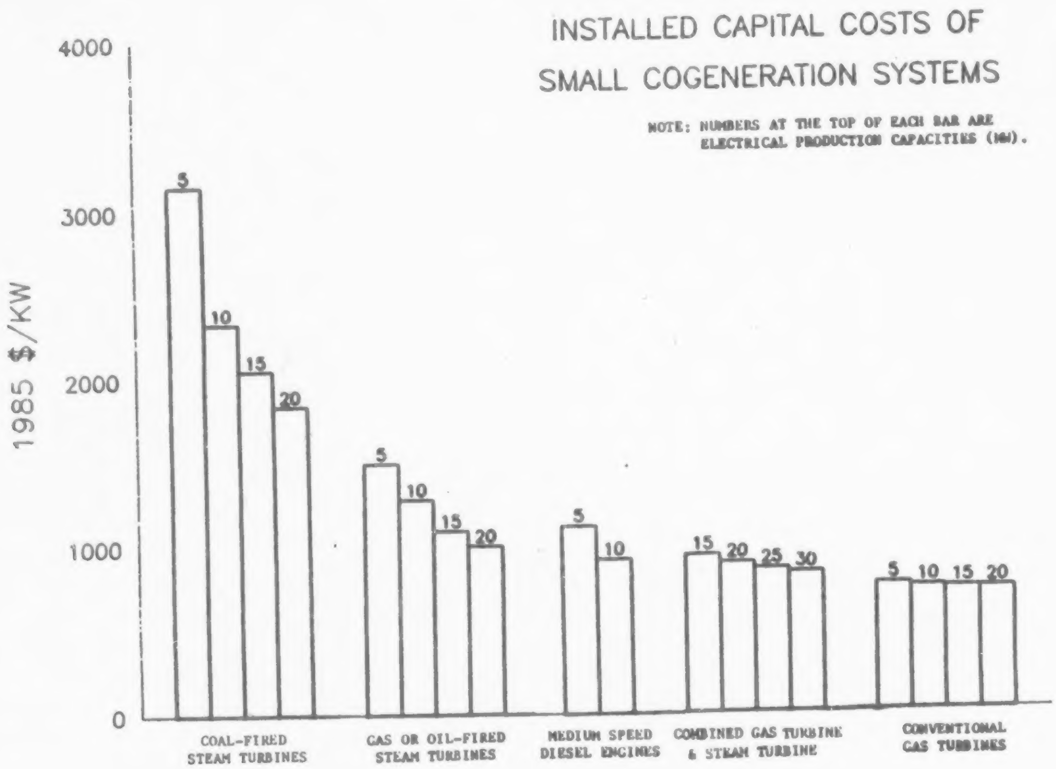


Figure 6

Source: (Eric D. Larson and Robert H. Williams, June 1985)

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Appendix on the Busbar Costs for Alternative Modes of Power Generation

The levelized busbar cost of electric power generation based on new plants is presented here by state for cogeneration based on natural gas fired steam-injected gas turbines, for central station power generation based on natural gas fired steam-injected.gas turbines, and for nuclear and coal-fired central station power plants. All costs are in mills per kWh (1985 dollars).

Cogeneration via Steam-Injected Gas Turbines: Because of the poor part-load performance of conventionally operated gas turbines, gas turbines with turbine exhaust heat recovery boilers have been used to date primarily for cogeneration applications involving steady (baseload) steam demands. The recent availability of steam-injected gas turbine cogeneration systems makes gas turbine technology applicable to variable steam load applications as well. With a steam-injected gas turbine system, excess high pressure steam available from the waste heat boiler when the process load declines can be injected into the combustor and directed through the turbine to produce more power, with a higher fraction of the consumed fuel converted to electricity than without steam injection. The result is good economic performance even with wide and unpredictable variations in the steam load, provided there is a market for the extra power produced when steam is injected.

Packaged steam-injected gas turbine cogeneration systems using a small steam-injected gas turbine are offered commercially by two companies -- International Power Technology (IPT) of Palo Alto, California, and Mechanical Technology, Inc. (MTI) of Latham, New York. IPT has installed one unit at San Jose State University and two units at the Sunkist Growers processing plant in Ontario, California.

A cost estimate for cogeneration based on the use of this turbine is shown in Table A - 1. The busbar cost presented here is the cost chargeable to power [the total cost (annualized capital costs plus operating cost) less the operating cost for an 83% efficient gas boiler that is replaced by the cogeneration system]. The gas turbine provides 3.5 MW of power and 20,000 lb. per hour of 205 psig steam, Monday through Friday, 7 am to 6 pm. For all other times it is assumed that the steam load is 10,000 lb. per hour and that the other 10,000 lb. per hour is injected into the combustor of the turbine, thereby increasing the electrical output to 4.75 MW.

Table A - 2 shows busbar cogeneration costs by state, based on the cost estimation procedure presented in Table A - 1. The natural gas prices assumed in these estimates are average state industrial prices levelized over the period 1990-2010, calculated assuming the price increases in real terms @ 3% per year, 1990-2010. The price in 1990 is taken to be 81.5% of the 1983 price, which is the American Gas Association's projection for the national average industrial gas price (Policy Evaluation & Analysis Group, March 15, 1985). The base 1983 industrial gas prices (American Gas Association, 1984) are converted to 1985 prices using the GNP deflator.

Table A - 2 also shows estimated average industrial electricity prices for each state levelized over the period 1990-2010. This price (in 1985 $) is assumed to be 30% higher than the 1983 industrial electricity price, to account for the effects of completing costly new power plants now under construction. Operationally, a 30% increase would be obtained if the price increased at an average rate of 2.5% per year, 1983-1990 and at half this rate thereafter. For comparison, the inflation-corrected industrial electricity price increased 6.9% per year, 1973-1983 (Energy Information Administration, April 1984), and the utility trade journal Electrical World projects that the inflation-corrected price for residential customers (no projection is made for industrial prices) will increase 3.8% per year, 1983-1990, and 1.4% per year, 1990-2000 (35th Annual Electric Utility Industry Forecast, September 1984).

Central Station Power Generation via Steam-Injected Gas Turbines: The remarkable increases in both efficiency and output possible via steam injection have led to interest in the technology for central station power generation, where all of the steam raised in the waste heat boiler is injected into the combustor and directed through the turbine to produce more power.

A cost calculation for central station power generation via a 108 MW (e) steam-injected gas turbine (STIG) is summarized in Table A - 3, which is based on an analysis made by the General Electric Company in a study carried out for the Pacific Gas and Electric Company (PG and E Engineering Department, July 9, 1984).

Table A - 4 shows busbar costs for STIG power by state, based on the cost estimation procedure presented in Table A - 3. The natural gas prices assumed in these estimates are the levelized average electric utility gas prices for the states, calculated for a 10% real discount rate, assuming the price increases in real terms @ 3% per year, 1990-2010. The price in 1990 is taken to be 86.6% of the 1983 price, which is the American Gas Association's projection for the national average electric utility gas price (Policy Evaluation & Analysis Group, March 15, 1985). The base 1983 electric utility gas prices are those tabulated by the Edison Electric Institute (Edison Electric Institute, 1984), converted to 1985 prices using the GNP deflator, except for those states where gas is little used or not used as fuel by electric utilities. For these states the base year (1983) prices are average industrial prices, as tabulated by the American Gas Association (American Gas Association, 1984), and the levelized gas price calculations by state are carried out as described above for STIG cogeneration. Busbar cost estimates based on industrial gas prices are those in parentheses.

Coal and Nuclear Power: US DOE estimates (Energy Information Administration, August 1982) of the busbar costs for nuclear and coal based electricity in the 10 regions shown in Figure A - 1 are also presented in Table A - 4. The US DOE cost estimates were converted to 1985 dollars from 1980 dollars using the GNP deflator. The costs are levelized over an expected 30 year life for new plants coming on line in 1995, assuming a 65% average capacity factor.

Table A - 1 Busbar Cost for Natural Gas Fired Cogeneration Using a Steam-Injected Gas Turbine (a)

	Busbar Cost (mills/kWh)
Capital (b)	16.27
Fuel (c,d)	7.788 x P
Turbine Overhaul Costs (e)	1.73
Water for Steam Injection (f)	0.43
Additional Technical Supervision (g)	1.11
Non-Turbine Related Maintenance (h)	1.66
Insurance (i)	1.04
	22.24 + 7.788 x P

Notes

(a) For an Allison 501-KH gas turbine system, for which the assumed life is 20 years. The annualized costs are calculated assuming a 10% real discount rate. The plant availability is assumed to be 95%. For details see (Eric D. Larson and Robert H. Williams, June 1985).

(b) The estimated installed cost is $5 million. All taxes and subsidies are neglected. Total annual electricity production is 36.13 million kWh.

(c) With no steam injection the fuel chargeable to power is 6024 BTU/kWh. With half the steam injected in the turbine the fuel chargeable to power is 8418 BTU/kWh. The weighted average heat rate is 7788 BTU/kWh.

(d) Here P is the industrial natural gas price [in 1985 dollars per million BTU (HHV)] levelized over the period 1990 to 2010.

(e) Every three years the turbine is overhauled at a cost of $220,000.

(f) During steam injection periods 1400 gallons of water are required per hour for injection, at a cost of $2 per 1000 gallons.

(g) $40,000 per year.

(h) $60,000 per year.

(i) $37,500 per year.

Table A - 2 Costs of Electricity from Alternative Sources (1985 mills per kWh)

	Busbar Cost for STIG Cogeneration (a)	Average Industrial Electricity Price (b)
Maine	86.6	61.8
New Hampshire	66.1	92.0
Vermont	64.8	76.0
Massachusetts	61.3	95.3
Rhode Island	65.7	102.5
Connecticut	71.6	98.1
New York	68.7	70.1
New Jersey	65.0	96.8
Pennsylvania	64.9	72.4
Delaware, Maryland, & DC	70.3	64.5
Virginia	64.4	61.8
West Virginia	66.2	51.6
Kentucky	60.3	54.7
Tennessee	57.4	61.3
N. Carolina, S. Carolina	63.0	53.1
Georgia	58.7	59.3
Florida	51.2	72.9
Alabama, Mississippi	57.6	66.1
Minnesota, Wisconsin	60.6	61.4
Michigan, Illinois	61.8	72.3
Indiana	58.3	65.0
Ohio	64.3	58.7
Arkansas	52.5	53.1
Louisiana	53.3	61.4
Oklahoma	49.6	57.4
Texas	55.6	68.5
New Mexico	53.0	78.1
Iowa, Missouri	57.8	59.4
Nebraska	53.9	52.1
Kansas	56.2	74.1
North Dakota	62.0	68.2
South Dakota	58.9	56.4
Montana	69.4	32.8
Wyoming	51.2	45.6
Colorado	59.6	54.7
Utah	48.8	60.3
California	67.0	88.9
Nevada	62.3	64.2
Arizona	54.9	69.1
Washington, Idaho	63.8	30.8
Oregon	65.5	44.1

Notes

(a) See Table A - 1.

(b) The industrial electricity price shown is 1.3 times the average revenue per kWh in 1983 (Edison Electric Institute, 1984). This would be the levelised price over the period 1990-2010 if the industrial electricity price were to rise in real terms @ 2.5% per year, 1983-1990, and at half this rate thereafter.

Table A - 3 Busbar Cost for Natural Gas Fired Steam-Injected Gas Turbines Used for Central Station Power Generation (a)

	Busbar Cost (mills/kWh)
Capital (a,b)	9.51
Fuel (a,c)	6.8 x P
Fixed O&M (d)	1.62
Variable O&M (d)	4.25
TOTAL	15.38 + 6.8 x P

Notes

(a) These cost estimates are for the GE LM5000 gas turbine modified for steam injection, with intercooling. With steam injection and intercooling the turbine capacity is 108 MW (e), the heat rate is 6800 BTU per kWh (HHV), and the estimated capital cost in 1983 $ is $500 per kW, or $530 per kW in 1985 $ (PG and E Engineering Department, July 9, 1984).

(b) For a 10% discount rate and a 20 year plant life, the capital recovery factor is 0.1175. The capacity factor is assumed to be 75%. Taxes and subsidies are neglected.

(c) Here P is the fuel price (in 1985 dollars per million BTU) levelized over the 20 year life of the plant.

(d) In 1983 dollars the fixed O&M cost is estimated to be $10 per kW-year and the variable O&M cost 4 mills per kWh (PG and E Engineering Department, July 9, 1984).

Table A - 4 Levelized Busbar Costs for Central Station Power Generation

		1985 mills per kWh
Region I		
1.	Nuclear @ $2020/kW	55.2
2.	Coal @ $1190/kW	60.1
3.	Natural Gas-Fired STIG Plant @ $530/kW	
	Maine	(71.6)
	New Hamphire, Vermont	(53.1)
	Massachusetts	46.4
	Rhode Island	44.6
	Connecticut	(58.4)
Region II		
1.	Nuclear @ $2130/kW	57.8
2.	Coal @ $1240/kW	56.7
3.	Natural Gas-Fired STIG Plant @ $530/kW	
	New York, New Jersy	48.0
Region III		
1.	Nuclear @ $1930/kW	53.8
2.	Coal @ $1190/kW	52.8
3.	Natural Gas-Fired STIG Plant @ $530/kW	
	Pennsylvania	(52.6)
	Delaware, Maryland, & DC	51.3
	Virginia, W. Virginia	(53.0)
Region IV		
1.	Nuclear @ $1860/kW	52.2
2.	Coal @ $1160/kW	56.7
3.	Natural Gas-Fired STIG Plant @ $530/kW	
	Kentucky, Tennessee	44.8
	N. Carolina, S. Carolina	(51.0)
	Georgia, Alabama	49.6
	Florida	35.1
	Mississippi	39.3
Region V		
1.	Nuclear @ $2040/kW	55.9
2.	Coal @ $1230/kW	54.5
3.	Natural Gas-Fired STIG Plant @ $530/kW	
	Minnesota	46.6
	Wisconsin	47.8
	Michigan	49.9
	Illinois	56.4
	Indiana	48.4
	Ohio	56.4

Table A - 4, cont.

Region VI

1.	Nuclear @ $1860/kW	52.2
2.	Coal @ $1220/kW	37.9
3.	Natural Gas-Fired STIG Plant @ $530/kW	
	Arkansas	40.2
	Louisiana, Texas	40.0
	Oklahoma	33.9
	New Mexico	43.8

Region VII

1.	Nuclear @ $1970/kW	54.6
2.	Coal @ $1180/kW	55.1
3.	Natural Gas-Fired STIG Plant @ $530/kW	
	Iowa	45.7
	Missouri	51.8
	Nebraska	40.5
	Kansas	38.6

Region VIII

1.	Nuclear @ $1950/kW	54.3
2.	Coal @ $1280/kW	39.8
3.	Natural Gas-Fired STIG Plant @ $530/kW	
	North Dakota	(50.1)
	South Dakota	(47.4)
	Montana	(56.5)
	Wyoming	(40.8)
	Colorado	45.2
	Utah	(38.5)

Region IX

1.	Nuclear @ $2100/kW	57.6
2.	Coal @ $1270/kW	57.6
3.	Natural Gas-Fired STIG Plant @ $530/kW	
	California	55.2
	Nevada	(50.4)
	Arizona	39.7

Region X

1.	Nuclear @ $2110/kW	57.6
2.	Coal @ $1230/kW	59.7
3.	Natural Gas-Fired STIG Plant @ $530/kW	
	Washington	(52.6)
	Oregon	(53.2)
	Idaho	(50.6)

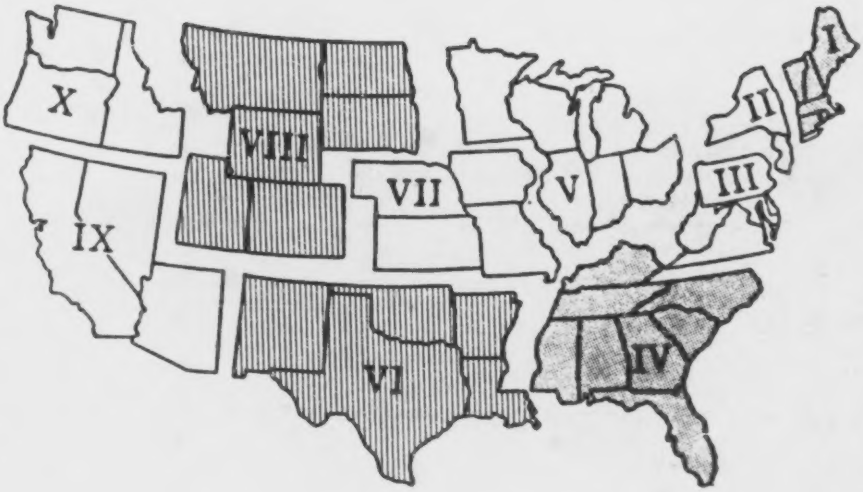

Figure A-1

Regions for which the Busbar Cost Comparisons of Table A-4 were made.

Senator Evans. Thank you very much.

Next, Mr. Gent.

STATEMENT OF MICHEHL R. GENT, PRESIDENT, NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

Mr. Gent. Thank you, Mr. Chairman. As you indicated, my name is Michehl Gent. I'm the president of the North American Electric Reliability Council. I deeply appreciate your invitation to present testimony, and I also appreciate your committee's interest in the reliability of America's electric supply.

The North American Electric Reliability Council is a nonprofit corporation owned by all the electric utilities in North America. We are the product of both the public's and the industry's concern that followed the Northeast blackout in 1965. Our charge is to see that cascading outages of the type that happened in 1965 never occur again.

This vigilance requires continuous assessment and it is from this assessment that this testimony has been prepared.

The electric systems of Canada, the United States, and Baja, Mexico operate in unison. However, in my statement, I have attempted to speak only of the United States. The makeup and operation of NERC is well-documented, so we have not included anything about NERC in our testimony, but we'd happy to supplment it if you find that information useful.

Our written statement covers those areas in which you have shown a concern and areas in which we have expertise. We have divided the statement into four subject areas. You'll find a section on the demand side, the supply side, the assessment of the power supply adequacy for the next 10 years, and finally a section on transmission issues.

My written statement is far too long and far too complicated to read and, having seen some of Tuesday's events on TV on C-SPAN last night, and having heard in the sound room today some of this morning's, I am going to refrain from restating some of the findings that you've already heard.

I'd like to summarize some of my conclusions that are specific, however.

On the demand side, the Council forecast is not my forecast or the forecast of my staff; it's the aggregated forecast of individual electric utilities around the country. We have commissioned our industry's experts; that is, we have drafted our so-called experts, formed a committee or a task force, and tried to find a way of discussing the uncertainty of such variables as the economy, unemployment, price of fuel, and all those other variables we've heard about today in two days ago.

We have, we think, for the first time tried to do or successfully quantified the degree of uncertainty. I'm sure you will not be surprised to learn that if you try to put certainty within 80 percent bands, that you'll find growth rates from 4.3 percent on the high side to a minus 0.3 on the low side. That's growth in demand per year.

Regarding the supply side, electric utilities in the United States are planning to install over 113,000 megawatts of generating capacity in the next 10 years. That sounds like a large amount; however, it is 17,000 megawatts less than a similar ten-year plan was last year. It's our estimate that capacity margins will be at or near minimum acceptable levels in most regions, even if electricity demand grows only at the present forecast rate of 2.2 percent.

Regarding assessment, it's a very detailed assessment that about 300 people participate in annually, and we publish an annual review each year. It's currently only in its draft form, but I'd like to share with you some of the salient points, that perhaps have not even been mentioned here today, or only passed on.

No. 1, some of the generating capacity being counted on in the next 10 years has not yet been committed. We feel that's terribly significant. We have an impending or a continuing dependence that's growing on demand management and cogeneration and renewables of other kinds, but we don't yet know how to judge or rate the reliability of that type of a resource. However, we are working on that.

The average age of our 455,000 megawatts of fossil fired units is now 17 years. In 10 years, that age will be 25 years of age, composite. We are working hard to find out what extended life does to a unit, but we're not ready to say that all units are the same, because all units have not been operated the same over the years.

With the well-documented financial risks of committing today to large capital-intensive projects that burn our cheapest fuels, utilities are adopting minimum capital outlay postures. We feel this could mean a default to short lead time projects in the future that may require us to burn our most precious and our highest cost fuels.

Waiting until that future date to commit could also place our electric system in jeopardy.

And, finally, the single most important step needed, in our view, to assure future electric supply is to reduce the lead time required to build generating units, generating units of any kind.

Regarding transmission issues, we have four networks on our continent. We have the western grid, we have the eastern network, we have Texas by itself, and we have Quebec by itself. Building more transmission would help, and you heard that this morning. But there are impediments. There are real impediments. There are specific examples in my testimony that cite specific lines and the problems we're having building these particular lines.

In closing, I commend you for being concerned today with a problem that may not become evident for another 10 years to the layman. America can solve its problem if this concern can be translated into our regulatory, economic and national security policies.

Thank you.

[The prepared statement of Mr. Gent follows:]

STATEMENT OF
MICHEHL R. GENT, PRESIDENT
NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL
TO THE
SENATE COMMITTEE ON ENERGY AND NATURAL RESOURCES
JULY 25, 1985

The North American Electric Reliability Council (the Electric Council) appreciates the opportunity to appear before your Committee and present its statement on future electric supply reliability.

Our statement is divided into five sections: Outlook for Reliability, The Demand Side, The Supply Side, Assessment of Power Supply Adequacy and Transmission Issues. The tables, figures and appendices referred to in the statement, along with a description of the Council and list of its relevant publications can be found at the end of the text.

OUTLOOK FOR RELIABILITY

The Electric Council expects the reliability of electric supplies to decline over the next ten years. By the mid-1990's, electric generating capacity margins will be near minimum acceptable levels in some parts of the country, even if electricity demands grow no faster than the present forecast rate of 2.2% per year.

Some of the generating capacity that will be needed ten years from now has not yet been committed to by utilities. Unless typically long lead times can be significantly shortened, this planned but uncommitted capacity may not be in service when needed. Co-generation, renewables, demand management and conservation will all play significant roles, but still account for only a fraction of the forecast need.

The future availability and performance of the electric utility industry's aging equipment is an additional unquantifiable factor. The composite age of our fossil-fueled steam electric generating capacity is 17 years. Even with the addition of all planned units over the next ten years, 1994 will find us with over 100,000 MW of fossil-fueled steam capacity that is more than 30 years old. The composite age of fossil-fuel steam capacity in 1994 will be 25 years. While the industry is working aggressively to implement life-extension programs, some capacity will be lost due to aging.

Even if future energy needs were more certain, utilities would be reluctant to commit to large power projects because of the associated large financial risks. Because of these risks, electric utilities appear to be adopting a minimum capital outlay posture for the future. This results in the least short-term cost to the customer and seems consistent with most regulatory mandates. This posture may cause a default over the long term to the highest cost alternatives and place our nation's future electric supply system in jeopardy.

Electric transmission systems will continue to be loaded heavily by economy energy transfers. These transfers, from areas with lower generation costs to areas with higher generation costs, help lower the cost of electricity to the customer but also increase the reliability burden on the electric power systems. When electric transmission systems are loaded to their maximum safe limits continuously, little margin remains to handle the unexpected. As a result, reliability suffers. Building additional transmission would help, but significant impediments exist to block this partial remedy.

The resourcefulness of electric utilities in providing and maintaining the most reliable electric system in the world is the product of men and politics of a different era. The Electric Council is concerned that if our regulatory, economic, and national security policies do not reflect an increased awareness of the need for adequate future electric supplies, the specter of unreliable electric service may become reality.

THE DEMAND SIDE

Long-term electricity growth forecasts continue to be uncertain. Electric utility forecasters, after witnessing many years of steady 7+% per year electricity demand growth, did not anticipate the dramatic shift in electricity use following the price increases caused by the 1973-74 oil embargo. Ten-year forecasts of peak demand and electric energy growth have since been successively lowered with the present forecasts calling for a 2.2% per year growth in peak demand and 2.4% in electric energy. This year's forecast remains essentially the same as last year's.

Current Experience

In 1984, electricity use again surprised most forecasters. Spurred by a longer and stronger than expected economic recovery, annual electric energy use increased by 4.4% over 1983 and 2.3% over what had been forecast **(Table 1)**. All regions showed increases over 1983 and all but MAPP exceeded their energy use forecast for 1984. Peak demands, both summer and winter, also showed increases over both 1983 actual and 1984 forecasts in most regions.

A strengthening economy is reflected in the use of electricity. Although the growth rate of electricity consumption has moderated in recent months, the 12-month running average of electric energy requirements **(Figure 1)** continues to show an increase. For the 12 months ending May 31, 1985, net energy for load in the United States was 1.7% above the comparable period one year ago.

Ten Year Projections

The electric utilities in the United States are projecting peak demand and energy to grow over the next ten years about the same as projected last year. A summary of this year's peak demand and energy projections based on submittals to the U.S. Department of Energy on April 1, 1985 are shown in **Table 2**, and comparisons of last year's and this year's forecast growth rates are shown in **Table 3**. Growth rate comparisons must be used carefully since the numbers can vary noticeably by using different starting points. **Table 4** shows a comparison of this year's and last year's forecast for 1993, the last common year for both forecasts. The most significant observation that can be made from these data is that the expected energy and peak demands for 1993 in this year's forecast is essentially the same as that in last year's forecast.

Utilities are relying on load management and conservation programs to restrain load growth. Some of our experts assert that these forecasts have been adjusted by up to 3% per year by these programs. There are practical limits to what load management and conservation programs can achieve; they will not eliminate the need for future generating capacity additions. Also, there is uncertainty as to whether these programs will continue to be supported by regulatory commissions and the public and uncertainty as to the reliability of these programs once they are operational.

Analysis of Forecast Sensitivity

Conflicting indicators from the economic recovery, load management and conservation programs and short-term weather effects are clouding long-term trends. A recently completed but as yet unpublished study by the Electric Council addresses the major variables in electricity forecasts and attempts to quantify, for the first time, the uncertainties of each.

Each year, the Electric Council and the nine Regional Reliability Councils publish ten-year forecasts of peak demand and energy requirements. In the case of the Regions, these are generally aggregations of the forecast values determined by the member utilities or power pools; the Council forecasts are in turn aggregations of the regional forecasts.

These aggregated forecasts are single number or point forecasts; that is, the forecast peak demand and energy requirement for a given period is reported as a single specific value or point. In actuality, any forecast in itself is not a point or single value but a probability distribution; the point or single number usually represents the probabilistic midpoint of a distribution such that the likelihood of exceeding it is equal to the likelihood of its not being exceeded. While this has been understood within the utility industry, increasing interest in and attention to our forecasts by non-industry groups has led to frequent misunderstanding of the forecasts, and occasionally to serious misapplications.

Furthermore, point or single value forecasts imply a greater degree of precision and certainty than is appropriate. The demand actually experienced is a function of many factors over which utilities have little or no control — including the performance of local and national economies, the price of fuel, domestic versus foreign production of goods and services, industrial and other policies, changing technologies, Federal and state legislation, and weather. These and many other factors greatly influence the actual peak demands and energy requirements of electric utilities, and make deviations from forecast values a common occurrence. Comparing actual demands to point forecasts may be misleading if the wide variations of causative factors involved are not appropriately expressed.

To develop bandwidths for the Electric Council's aggregated forecasts is a different task than the calculation of utility forecasts (with or without bandwidths), because the base line forecast is given as the aggregation of Regional forecasts. Essentially all of the factors that influence future demands have already been included in the calculation of individual utility, pool or regional forecasts; but since so many entities are involved, those doing the final aggregation cannot know completely how each component of the aggregated forecast has been treated. On the other hand, since the base line forecast is given, the Council only concerns itself with possible variations in the factors which influence forecasts.

A bandwidth methodology has been developed and applied to the ten-year peak demand and energy forecasts for the United States published by the Council in 1984. **Figure 2** displays sensitivity bands about the Council's forecast of summer peak demand, while **Figure 3** depicts similar bands about the 1984 electric energy forecast. Average annual growth rates are shown for the bands and the Council forecasts. In each case, a range of high band and low band forecasts is shown, with the shaded areas of the graphs representing the variations due to weather effects. In the case of the peak demand sensitivity bands (**Figure 2**) the range between the high and low bands grows to more than 250,000 MW by 1994. Given that ten years is a typical planning horizon, it is easy to see how difficult accurate capacity planning can be under these circumstances. Even five years into the future, the spread between the high and low band forecasts is 150,000 MW.

Only those factors whose variation would have major influences on the forecast were considered in the analysis. Those factors where changes in assumptions would result in relatively small variations in demand were excluded. In making judgments on each factor, however, the probability of a variation was considered as well as the effect on demand of a variation in the value of the factor. The combined effect was used as the basis for inclusion or exclusion of a given factor.

Forecasts were attempted using various combinations of fifteen factors or input variables. The set of factors selected that best replicated the Council demand forecast were:

- Real Gross National Product;
- Real Price of Electricity;
- Industrial Sector Employment; and
- Prior-Year Demand.

All fifteen are listed in **Appendix** 1, along with brief statements as to the reasons for exclusion of the factors not used. Except for industrial employment, the predictor variables were lagged one year — i.e., previous year input values are used in forecasting the contemporary year's demand.

The 1984 Council demand forecast was replicated by establishing relationships between demand and the predictor variables based on historical data for the period 1950 through 1983, and then applying these relationships to current base forecasts of the predictor variables. This was done using a standard regression analysis. Next, professional judgment was combined with available published forecasts of the predictor variables to derive high and low values for each input variable. This type of procedure is a form of decision analysis. The historical data and forecast input variables (high, base and low) are shown in **Appendix 2**. The confidence level of the spread in economic variables is such that the upper and lower bounds each have about 10% chance of being exceeded. These forecasts of predictor variables were used in the base model to develop the bandwidths. The predictor variables were used in combinations such that high and low forecasts of peak demand were obtained.

Weather was treated differently from the other variables since it is a random variable not dependent on the time elapsed from point of forecast or on other factors. National and regional economic and demand data and national climatological data were analyzed. As well, about 50 utilities were surveyed for the effect of weather on peak demand. It was concluded that extreme weather at the time of summer peak could increase or decrease the Council's aggregated summer peak demand by 3%. However, it was also concluded that, on a national basis, weather variations do not have a significant effect on aggregations of the Council's annual net energy for load. It should be emphasized that these conclusions regarding the effect of weather variations on demand and energy are applicable only on a national basis; they can not be applied to individual utilities, pools or Regions.

The ± 3% effect of weather on the aggregated peak demand forecast is indicated by the shaded areas **Figure 2**. There is approximately a 10% chance that the actual demand will be either higher or lower than the range of the forecast demand as influenced by the non-weather variables. Stated differently, there is approximately an 80% chance that actual demand will fall within the bounds set by the high and low cases.

Energy bandwidths were developed by applying the forecast annual load factor to the demand bandwidths for normal weather. A review of recent national historical load factor data indicated year-to-year variations of approximately ± 2 percentage points. This variation was applied to the high and low peak demand projections, which did not contain any effect of abnormal weather, to derive the band of energy projections. The effect of load factor variation is indicated by the shaded areas of **Figure 3.**

It should be emphasized that the methodology and the predictor variables used are applicable only to nationwide peak demand and energy aggregates. It would be incorrect and very misleading to attempt to apply this methodology and the base, high and low values of GNP, price of electricity, industrial employment, weather and load factor to individual Regions or other electric system entities.

THE SUPPLY SIDE

Electricity is unique among energy sources in that it must be produced at the precise moment it is required; it cannot be produced in excess at times of low demand and saved for use at times of peak demand. Thus, the capability to produce electricity must be in place when the need for it arises. A reliable supply of electricity is vital to the health and well-being of a modern economy — when demands cannot be served, industry, commerce and citizens' lifestyles suffer.

Given the uncertainty of future electric requirements and the critical nature of an adequate electric supply, it is important that utilities have the flexibility to respond to changing trends in future demand.

Planned Capacity Additions

United States' electric utilities are planning to install 113,200 MW of generating capacity from 1985 through 1994 (1). Coal and nuclear-fueled capacity additions amount to 42,200 MW and 46,300 MW, respectively. These additions and the total capacity over the coming ten-year period are shown in **Tables 5 and 6** and in **Figures 4 and 5.**

The total capacity planned to be added over the ten year period is about 17,000 MW less than shown in last year's ten-year projection. Nuclear projects removed from last year's capacity list include Midland 1 and 2 (1,194 MW), Marble Hill 1 and 2 (2,260 MW) and

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(1) Capacity additions as reported for the April 1,1985 to December 31, 1994 period in the April 1985 "Coordinated Bulk Power Supply Program" (IE-411) Reports of the Regional Reliability Councils.

Perry 2 (1,179 MW) in the ECAR Region, and Seabrook 2 (1,150 MW) in the NPCC Region. Since the Council's data has been prepared, the Tennessee Valley Authority announced a delay of their Bellefonte 2 unit (1,212 MW) from 1991 to beyond the ten-year reporting period. A comparison of this year's and last year's generating capacity projections for 1993 (the last common year of both forecasts) is shown in **Table 7.**

Coal-fueled generating capacity provides more than 50% of the electricity in the United States today. Despite coal's predominance, several regions will continue to depend heavily on oil or gas, while nuclear's share of capacity and energy is expected to grow in some areas. There is also a trend toward use of smaller units, as reflected by the increase in the number of planned oil/gas peaking units. The number of smaller units may continue to increase for several reasons. Smaller units take less time to construct and therefore may incur lower financing costs and may allow commitments to be postponed. These advantages are significant considering the uncertainty of demand growth and the uncertainty of rate treatment.

The advantages of smaller units can also be obtained by fluidized bed combustion (FBC) units. FBC units have the added advantage of meeting SO_2 limitations without the use of scrubbers, and are now proving their feasibility through several demonstration projects.

Cogeneration

Four regions or subregions of the Council expect to have significant amounts of cogeneration capacity in service by 1994. The total cogeneration in these four areas is expected to reach about 9,000 MW in 1994, and represents about 5% of their total capacity.

Area	Expected Cogeneration Capacity (1994)	 % of 1994 Area Capacity
ERCOT	4,270 MW	6.8
New England	1,182 MW	5.3
California	2,527 MW	4.5
MAAC	1,029 MW	2.1

Cogeneration has been used for many years to produce electricity in connection with industrial processes where steam is a requirement. Favorable tax and regulatory treatment in the United States have increased the potential use of cogeneration and small power production. The potential for cogeneration appears to be increasing rapidly. Some reputable parties are estimating cogeneration potential to exceed 20,000 MW. However, the situation is very fluid, and any one of a number of factors could change the amount of cogeneration capacity that is actually placed in service.

The fact that the construction lead time is short may be a significant advantage to the utility, both financially and in the flexibility of the planning process. Of concern is the reliability and dependability of cogeneration as a capacity and energy source, and the long range prospect for continued operation. Since cogenerators are permitted to use natural gas or oil as fuel, their incentive to continue operation will be subject to price variations of these fuels. Many will operate as base load generation, and may not respond effectively to the need to reduce output at times of light utility demand or during emergencies. It is anticipated that cogenerators will be more responsive to process needs than to the needs of reliable electric service. Many will not participate in control of voltage and frequency.

Retirements

Planned unit retirements over the 1985-1994 period total 12,400 MW, and amount to about one year's demand growth. Increasing attention is being given to extending the life of existing units and to improving their availability. These life extension programs are influencing decisions on capacity additions and retirements and account for some of the deferrals and cancellations.

Projected Energy and Fuel Use

United States utilities expect to generate nearly 3 quadrillion kilowatthours of electricity in 1994. This is one-fourth more electricity than they generated in 1984. Coal-fired generation is projected to keep its better than one-half share of total electricity generation in the United States by 1994, while nuclear will increase its share from 17.5% to 22% and oil/gas decreases to 12% as shown in **Figure 6.** It is interesting to note that just nine years ago, nuclear units had been projected to provide 30% of the United States electricity generation in 1985. Now that figure stands at only 17.5%.

Nuclear generated electricity represents a much higher fraction of electricity supply in other countries and is expected to increase more rapidly than in the Unites States. For example, the percent share of nuclear generation to total electricity generation is expected to increase from 1984 to 1995 in France from 59 to 75%, in the United Kingdom from 19 to 37%, in West Germany from 24 to 33%, in Japan from 22 to 35% and in Taiwan from 25 to 48%.

United States' utilities continue to purchase significant quantities of electric energy from Canadian utilities for mutual advantage. In the four regions where these transactions occur, the size of the transaction varies from 0.2% of the ECAR energy requirements to 12% of the NPCC (U.S.) energy requirements in 1985. The size of these transactions is expected to increase through the 1980's, particularly in NPCC. The impact on reliability of these increased NPCC transactions is being studied by utilities in NPCC, MAAC, and ECAR.

ASSESSMENT OF POWER SUPPLY ADEQUACY

In the United States, installed generating capacity is forecast to be near the minimum acceptable levels in some regions by 1994 and may not be sufficient unless the following important actions are taken:

- Complete and place in service generating units which are under construction.
- Use life extension, refurbishment and maintenance programs to get the most out of existing generating equipment.
- Develop capacity alternatives having shorter lead times for licensing and construction.
- Resolve the acid rain question in a manner that will not result in a reduction of existing coal-fired capacity or lengthy outages for retrofitting units.
- Commit to new capacity that has a demonstrated need.

Complete Units Now Under Construction

At present, there is 46,300 MW of nuclear capacity under construction. During 1984, 3 units totaling 2,383 MW were indefinitely delayed and 8 units totaling 9,040 MW were canceled. In addition, 26 units had their service dates delayed an average of 7 months each. Of the 16 units scheduled for commercial operation during 1984, only 7 units totaling 7,566 MW were placed in service. Based on continuing difficulties in satisfying all regulatory requirements and obtaining operating licenses, the service dates of the remaining nuclear units must be considered questionable.

United States electric utilities also have 24,000 MW of coal-fired capacity under construction. These units are not immune to problems, but the outlook for timely completion is much brighter than for nuclear. Since last year, 18 coal-fired units totaling almost 10,000 MW were placed in service out of the 19 units that were planned. However, 8,300 MW of coal-fired capacity was dropped from the forecast while less than 3,700 MW was added; 24 units totaling 12,500 MW were delayed an average of 20 months each. Another 18,200 MW of coal-fired capacity is planned but not yet under construction. It is questionable if all of that amount can be licensed and constructed by the time it is needed. Construction was begun on only one large coal-fired unit in the past year.

Acid Rain

In the past, the effect of acid rain legislation was considered to be heaviest east of the Mississippi River. However, calls for further restriction in SO_2 and NO_x emissions are being voiced in other areas as well. In the U.S., there remains a need to further document cause-effect relationships, assure effectiveness of any program offered for adoption, and achieve consensus regarding societal costs. Further emission restrictions would lower unit availability and increase the power required to operate new emission control equipment. Any control equipment added to existing plants would require extensive unit downtime while installation was made. While the outages required for retrofitting units with new control equipment can be scheduled in phases, some replacement capacity would still be required.

Shorten Lead Times

A reduction in the amount of time between commitment and operation of a generating unit (Lead Time) would be of great benefit in capacity planning. In fact, it could be considered the single-most important step needed to assure future electric supply adequacy.

Smaller units are also being considered as a means of shortening the time between commitment and operation and reducing capital requirements. The smaller unit's greater ratio of shop labor to field labor should minimize construction time. This is particularly true of combustion turbines that burn oil and natural gas. Another type of unit being studied uses fluidized bed combustion, which can burn a wide range of coals or even refuse in an environmentally acceptable manner. The smaller units should make siting easier, and also ease financing of projects.

Life Extension and Refurbishment

For various reasons, many systems have made studies of extending the life of existing units or of doing major maintenance to improve availability. Some have entered into programs to implement the results of the studies. These programs have the effect of increasing capacity in a short period of time. They can also allow delaying the decision date on new capacity additions.

Capacity Utilization

Every industry providing a product or service must allow for the repair and maintenance of equipment and the unavailability of productive resources. The more essential that product or service, the greater the need for a margin of safety to ensure a dependable supply. Although electricity is essential to the health, safety, and economic well-being of this nation, the need for a generating capacity in the United States utility industry is not well understood.

In 1982, a study was commissioned to address a misconception by national policymakers that current generating capacity, because it was about one-third greater than the experienced demand, provided for many years of economic growth without the need for building new generating capacity. That study resulted in a special Electric Power Research Institute (EPRI) report, "Generating Capacity in U.S. Electric Utilities."

In January 1984, the Board of Trustees of the Electric Council asked EPRI to update that report to reflect the most recent experience. Like its predecessor, the most recent report, issued in December 1984, does not address plans and objectives of individual utilities, but is intended to provide a general basis for communicating how generating capacity is used and how much is needed to support economic growth.

The updated study covers the period from 1976 through 1983 and confirms the conclusions of the original report with the finding that an average 91 percent of the nation's generating capacity was needed over the past eight years to provide reliable service to current electricity users. The remaining 9 percent provides an economic margin for operating the most fuel-efficient plants and a small margin for serving additional demand. The updated report also shows that capacity utilization for electric utilities has been consistently high when compared with capacity utilization in other industries.

Capacity margin is the difference between peak demand and total demonstrated capacity (the sum of the net dependable capacity of all generating units installed at a given time, plus scheduled capacity purchases, less scheduled capacity sales). When expressed as a percent, the capacity margin in megawatts is divided by the total demonstrated capacity. Because capacity margin is a fraction of "capacity," its use facilitates an explanation of that amount of capacity which is unusable due to forced outage, partial outage and derating, and scheduled maintenance.

As an example, in the summer of 1983, the peak demand for electricity reached 448,000 MW, which was 75% of utilities' demonstrated capacity **(Figure 7)**. However, 15% of that demonstrated capacity was not available for service, leaving an **operating margin** of 10% **(Figure 8)**. The three principal causes of this unavailable capacity were preventive maintenance, forced outages of total plant, and partial outages and deratings **(Figure 9)**. The capacity unavailable at time of peak demand, and the resulting margins, have varied over the last eight years, showing no specific trend **(Table 8)**.

Every industry which provides some product or service is interested in how its production capacity is used. While electricity is different in many ways from other products and services, some useful comparisons can be made. Each industry has its own ways of measuring the utilization of its production capacity. Nevertheless, essentially all production measures express output as a fraction of capacity to produce output. A sampling of these measures, all based on **available capacity**, is shown in **Figure 10**.

Electric utility capacity utilization can also be measured based on **available capacity** **(Figure 11)**. On this basis, 88% of the capacity available to generate electricity at the time of the 1983 summer peak was actually used. Compared with that of other industries, utilization of electric generating capacity has been consistently high **(Figure 12)**.

Over the last eight years, an average of 91% of demonstrated electric generating capacity was required to meet customer demands — 17% was unavailable and 74% actually produced electricity. This left an operating margin of 9%. Given the uncertainties utilities have faced over the last ten years, this record of performance is commendable. These are only averages, and regional and individual utility figures will certainly vary from them. The concept however, will not vary. Before anyone can hope to judge how much generating capacity will be needed for the future, they must first thoroughly understand these basic concepts of capacity utilization.

Future Supply Capability

The amount of electric generating capacity projected to be in service in the United States by 1994 can support an average annual growth in electric peak demand of 2.2%. Because some of the capacity additions projected for service are not under construction, they could be delayed or canceled and we could face a serious gap in our electric supply. For every 10,000 MW of capacity below the "planned" level for 1994, the supportable peak demand growth rate will drop by 0.15% per year. That is, if 1994 capacity is 50,000 MW less than projected, the supportable peak demand growth rate would be 1.4% per year (2.2% minus 5 times 0.15%). This relationship is shown graphically in **Figure 13.**

While electricity usage over the last ten years grew more slowly than in previous years, it still increased faster than real Gross National Product **(Figure 14).** Most significantly, this growth occurred despite rising costs of electricity. All energy costs increased during this period and, coupled with slower economic growth, drastically reduced usage of all energy.

Most economists agree that Gross National Product will increase more than 2.2% per year over the next decade. Given the close correlation between the growth in electric demand and the growth in Gross National Product, a supply-demand gap is a real possibility. A strong public consensus is needed to assure an adequate electric future.

TRANSMISSION ISSUES

The transmission systems continue to be heavily loaded a high percentage of the time with economy energy transfers. As a result, there is a greater vulnerability to system disturbances and customer service interruptions. Building more transmission lines would increase the capability to transfer economy energy and, at the same time, increase the capability to respond to emergencies. However, there are impediments and disincentives to planning, licensing and constructing new lines.

Heavy Transfers

The attempt to reduce the amount of oil-fired energy began with the oil embargo of 1973 when the rapidly rising oil and gas prices caused large differences in energy costs. By transferring significant amounts of coal or hydro-generated electricity to replace that generated from oil and gas, sizable savings were achieved, even after transfer costs were considered. These savings were generally divided between purchaser and supplier to benefit the customers of both utilities.

Energy cost differences between regions continue to justify very high transfers. For example, Northeastern utilities rely heavily on imports of non-oil-fired energy from Canada. Southeastern systems transfer large amounts of energy generated from coal among subregions. The Mid-Atlantic area imports significantly from the central U.S. and vast amounts of Pacific Northwest hydro-generated energy are transferred to the Pacific Southwest. To illustrate the degree of utilization, **Figure 15** shows actual 1983 and 1984 transmission use in MAAC and WSCC, compared to transmission capabilities.

These transfers are expected to continue through the mid-1990's, based on estimates of demand growths, fuel prices, and cancellation of generator additions.

Reliability

Transmission is used to exchange large quantities of electric energy during localized generating capacity shortages. For example, severe cold weather in the winter of 1984-85 struck broad regions of the northeastern United States and caused many of the eastern and midwestern systems to lose generating capacity. At the same time, customer heating demands climbed to new highs. This combination created a shortage in electricity supply. Unaffected utilities quickly increased available generation and used the transmission network to deliver power to areas where supply was in jeopardy. Transmission was also crucial in serving the customers in Texas and the Gulf States during the recent severe winter.

Excessive transactions between pools and regions can adversely affect power system reliability. While a severe disturbance during normal transmission loading may go unnoticed by customers, the same disturbance occurring while the system is heavily loaded is more likely to cause consequential outages and customer interruptions. Compounding this effect is the phenomenon of parallel path flow, also called loop flow or circulating flow. When two interconnected utilities have transmission ties with a third utility, and are transferring energy, the adjacent utility transmission system will be a path for power flows in parallel with the main path. For example, **Figure 16** shows the effect of non-simultaneous flows from ECAR to MAAC and from Ontario Hydro to NYPP. Note that 7% of MAAC's purchases flow through NYPP and 43% of NYPP's purchases flow through MAAC. Coordinated planning and control of schedules within and between regions is a constant activity of system operators and planners to control line flows to safe levels.

Impediments to New Transmission

A number of proposed key transmission additions in various parts of the country, which could both increase transfer capability and improve reliability, are being denied or delayed.

Among the general impediments to the construction of new bulk power transmission lines are:

- Justification of new transmission lines is accomplished through consideration of economic benefits and reliability requirements. Today, regulators and utilities tend to discount uncertain future benefits such as prospective but non-contract power transactions and general improvements in regional reliability. Consequently, transmission lines that might have been built in the past on a reasonable expectation of future benefits are not likely to go forward today.

- Licensing Procedures: The lengthy regulatory process for issuing licenses for new transmission hampers new construction. Likewise, open-ended regulatory processes, where an action can be re-opened even after a license has been issued, present serious impediments to the timely construction of new facilities.

- Conflicting Jurisdictions: Conflicts among local, state and federal agencies in licensing matters can result in extensive delays in authorizing new transmission lines. Similarly, where transfers between two systems result in the need for reinforcements in different jurisdictions, extensive delays generally result.

- Lack of Incentives: Regulatory treatment which assigns the economic benefits of a new facility solely to the customer, while the utility bears all of the risks, creates a disincentive for new transmission.

Examples of specific projects that have been delayed:

- The Washington, D.C. 500 kV loop has been delayed for several years. The development of an EHV transmission network in the Washington, D.C. area would significantly increase the ability to import energy into MAAC. Completion of the loop is now scheduled for 1991. Efforts to accelerate this schedule are being pursued.
- The delay in restarting Three Mile Island #1 creates an impediment to transfers. In addition to providing low cost electricity, TMI is important for voltage support. Without this voltage support, the utilities in MAAC are not able to replace as much oil-fired generation in its eastern area with coal-fired electricity from western Pennsylvania and Ohio.
- Construction of a 500 MW dc tie between ERCOT (Texas) and the Southwest Power Pool is being delayed by a Texas PUC order to provide a more comprehensive examination of possible health effects.
- The 72-mile Jackson's Ferry-Axton 765 kV line in Virginia will extend Appalachian Power Company's EHV system to reinforce the electric supply in the Axton area. The Company applied in early 1974 to build the line, and

after hearings, approvals, interventions, and appeals, permission to construct was granted in 1982. Completion is now expected in September 1985.

- The delay of the Mansfield-Harding 345 kV circuit in **Ohio**, originally scheduled for April 1977, hampers Cleveland Electric Illuminating Company's ability to transfer emergency power and normal economy energy transfers. Construction of the unfinished 11 miles was delayed by legal disputes with two adjoining municipalities regarding line routing. Having reached agreement over the routing and acquired the right-of-way, completion by summer 1985 depends on federal and state approval.

- The Belle River-Jewell 345 kV line in **Michigan** is necessary to deliver power from the new Belle River Power Plant to the system. Without this line, power transfer from Ontario Hydro to Michigan is restricted during certain circuit outages and adverse weather conditions. Application was made in January 1983 and approved for service in July 1985. Currently, the line is held up in court action for township zoning approvals and property condemnation which is estimated to delay the completion until March 1987.

- The 39.3-mile Tewksbury-Seabrook 345 kV line will be needed to deliver power to **New Hampshire and Massachusetts** when the Seabrook unit comes on line. There is a high probability that the line will not be completed in time due to several uncertainties including regulatory and financial problems. This delay will force non-economic generation patterns to prevent system instability.

- The Noxon-Pine Creek 230 kV #2 line in the **Pacific Northwest** has been delayed until October 1987 due to permit acquisition problems with the U.S. Forest Service and due to budget constraints. Delay of this project in conjunction with delay of Bonneville Power Administration's Taft-Bell 500 kV transmission line may lead to serious line overloading problems for certain outage cases when all four Colstrip generating units are on line in 1986.

- The existing transmission interconnection between **Colorado and New Mexico** is a weak transmission link in the eastern area of the WSCC. The completion of the Rifle-San Juan 345 kV line in 1986 after a two-year delay will significantly strengthen the interconnection providing a major improvement in reliability. Until the line goes into service, power flows through Colorado will continue to stress existing facilities requiring generation curtailments and resulting in separation, loss of load and generation for certain system disturbances.

- The Devers-Valley-Serrano 500 kV line in **southern California** is presently under construction and planned to be operational in 1986 after a two-year delay from the original planned date of 1984. The delay is a result of a licensing proceeding spanning four years. The license was finally issued on October 3, 1984. The line is required for local reliability. In addition, there is a resulting 400 MW gain in transfer capability from Arizona to California. The gain in transfer capability will be delayed until the full project is in operation at 500 kV.

An example of where impediments have been overcome and where transmission expansion has been successfully accomplished is in **Florida**. Since 1980, over 900 miles of 500 kV transmission has been added in the Southern and Florida Subregions of SERC in order to support sales of coal-generated power to oil-dependent areas of Florida.

A Substitute For New Transmission

Impediments to building new transmission coupled with the incentives to increase transfer capability have resulted in the increased application of innovative devices and shortcut methods involving complex control and protection systems. These special devices and techniques are used to disconnect generation, open lines, shed loads, and to operate other control devices. Initially, these devices and schemes (collectively labeled "Special Protection Systems") were used as temporary fixes to provide the additional time needed to complete new transmission lines. This temporary use has evolved into more permanent applications and dependencies. Experience has shown that the reliability of these devices is inconsistent, and that they have caused or extended a number of outages.

Utilities are using special protection systems and restoration techniques to raise interconnection loadings and to reduce customer costs. Faced with impediments to the construction of new transmission lines, it is expected that utilities will take more risks and customer interruptions will increase. The outlook is for higher loadings and greater concern for reliability.

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6. Generating Unit Additions, Retirements and Conversions: 1985-1994
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13. Supportable Demand Growth versus Capacity Additions
14. Growth of GNP, Electricity and Electricity Prices
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16. Parallel Path Flows

Appendices

1. Disposition of Forecast Variables Considered
2. Historical Data and Forecast Variables

Table 1

1984 Actual Peak Demand and Energy (United States)

	Percent Increase over 1983 Actual	Percent Increase over Forecast
Summer Peak Demand	0.8	1.0
Winter Peak Demand	6.2	6.6
Annual Energy	4.4	2.3

Table 2

Forecast Peak Demand and Energy
(United States)

	1985	1994
Summer Peak Demand (Thousands of MW)	465.1	566.8
Winter Peak Demand (Thousands of MW)	422.9	519.1
Annual Energy (Thousands of GWh)	2,499.4	3,080.6

Table 3

Forecast Average Annual Growth in Peak Demand and Energy - %/yr. (United States)

	This Year's Forecast (1985-1994)	Last Year's Forecast (1984-1993)
Summer Peak Demand	2.2	2.5
Winter Peak Demand	2.3	2.5
Annual Energy	2.4	2.7

Table 4

Annual Energy and Peak Demands
Comparison of Forecasts for 1993
(United States)

	This Year's Forecast for 1993	Last Year's Forecast for 1993	Percent Change
Summer Peak Demand (Thousands of MW)	554.5	559.4	(0.9)
Winter Peak Demand (Thousands of MW)	509.5	511.2	(0.3)
Annual Energy (Thousands of GWh)	3,013.1	3,039.9	(0.9)

Figure 10

Table 5

NERC Generating Unit Additions, 1985-1994

NUCLEAR	U.S.	
	NUMBER OF UNITS	THOUSANDS OF MW
Planned, But Not Utility Authorized	0	0
Regulatory Approval Pending	0	0
Regulatory Approval Received, But Not Under Construction	0	0
Under Construction Less Than 50% Complete	6	7.0
Under Construction More Than 50% Complete	35	39.3
TOTAL NUCLEAR ADDITIONS*	41	46.3

COAL	U.S.	
	NUMBER OF UNITS	THOUSANDS OF MW
Planned, But Not Utility Authorized	35	14.9
Regulatory Approval Pending	4	2.2
Regulatory Approval Received, But Not Under Construction	5	1.1
Under Construction Less Than 50% Complete	21	13.6
Under Construction More Than 50% Complete	21	10.4
TOTAL COAL ADDITIONS*	86	42.2

*Totals may not add due to rounding

Table 6

Total Generating Unit Additions, Retirements & Conversions, 1985-1994
(United States)

	Thousands of MW
NUCLEAR	46.3
COAL	42.2
HYDRO	3.2
OIL/GAS	6.7
PUMPED STORAGE	5.2
COGENERATION	6.6
OTHER	2.9
TOTAL ADDITIONS*	113.2
RETIREMENTS	12.4
OIL-TO-COAL CONVERSIONS	4.5

*Total does not add due to rounding

Table 7

United States
Projected Generating Capacity - for 1993 Summer
Comparison of Forecasts
(Thousands of MW)

Fuel Type	This Year's Forecast for 1993	Last Year's Forecast for 1993	MW Change in 1993 Forecast	% Change in 1993 Forecast
Coal	306.5	312.8	(6.2)	(2.0)
Nuclear	110.4	115.6	(5.2)	(4.5)
Hydro	68.5	66.9	1.6	2.4
Oil/Gas	186.6	183.1	3.5	1.9
Other*	32.2	32.2	0.0	0.0
Total	704.3	710.6	(6.3)	(0.9)

*Includes pumped storage and cogeneration

Table 8

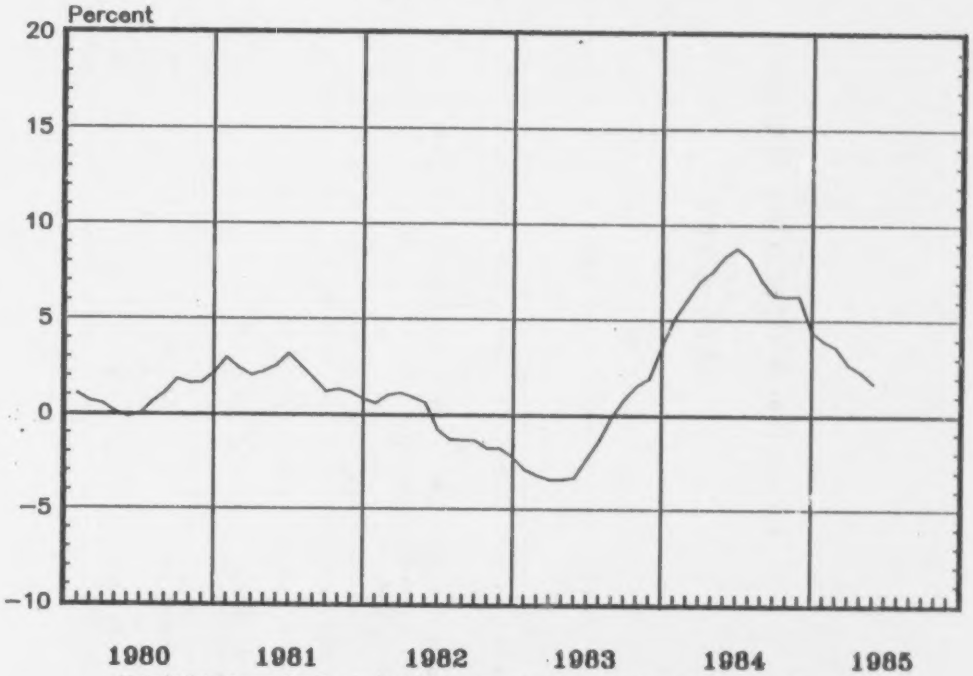
Capacity & Operating Margins

1976–1983

U.S. at Time of Peak Demand	1976	1977	1978	1979	1980	1981	1982	1983	Average
Demonstrated Capacity (GW)	465	506	531	544	558	572	586	596	
Peak Demand (GW)	360	387	396	398	427	428	415	448	
Capacity Margin (%)	26	24	25	27	23	25	29	25	26
Maintenance (%)	4	4	5	5	5	5	5	6	5
Forced Outages (%)	6	7	6	8	7	7	7	6	7
Partial Outages and Deratings (%)	5	5	6	5	5	5	5	3	5
Unavailability (%)	15	16	17	18	17	17	17	15	17
Operating Margin (%)	11	8	8	9	6	8	12	10	9

NERC – United States

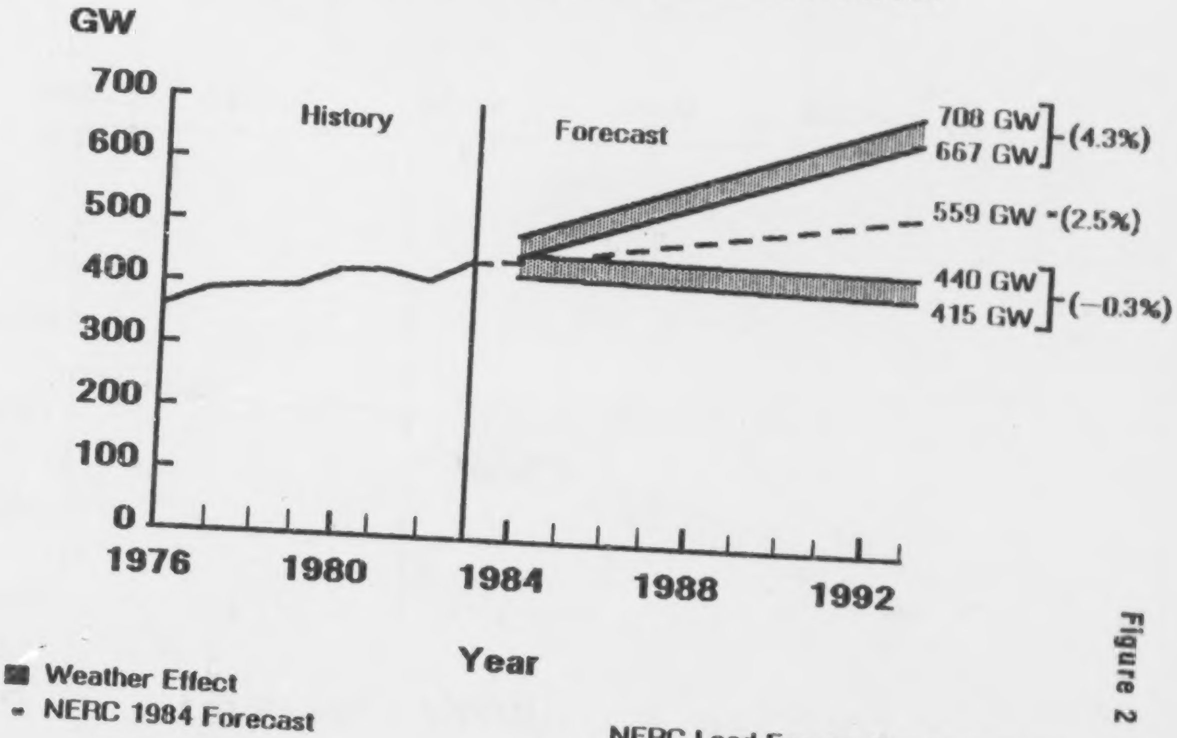
Net Energy for Load: 12–Months Ended vs. Previous 12 Months



Note:Point shown for December'84 is January–December'84 vs.January–December'83

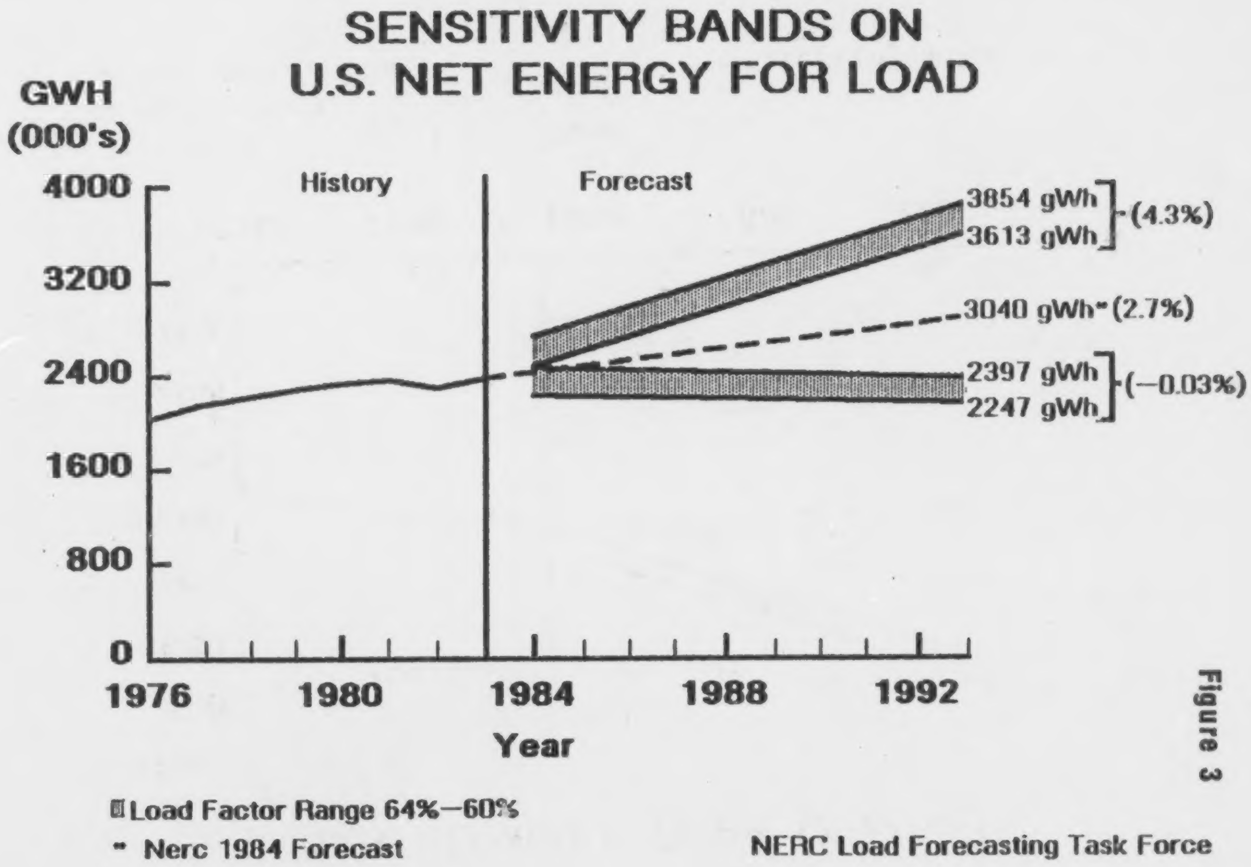
Figure 1

SENSITIVITY BANDS ON U.S. SUMMER PEAK DEMAND



NERC Load Forecasting Task Force

Figure 2

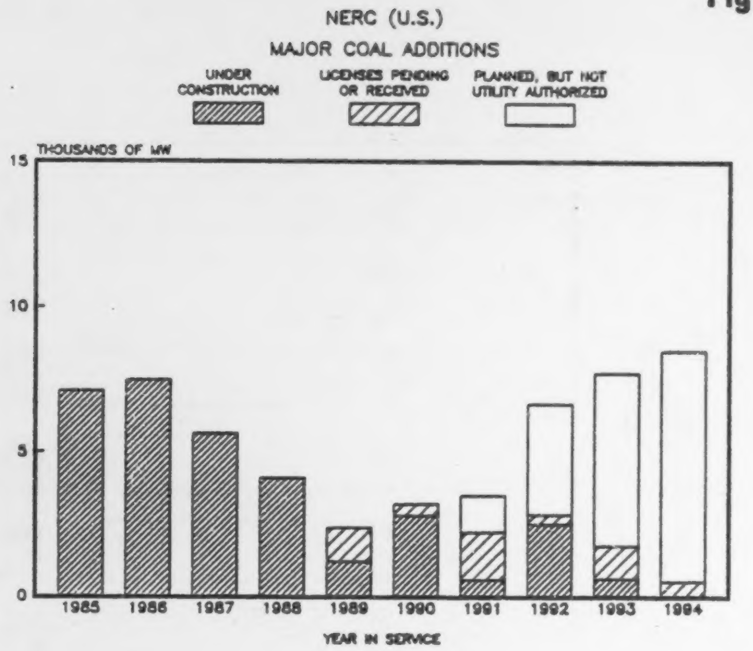


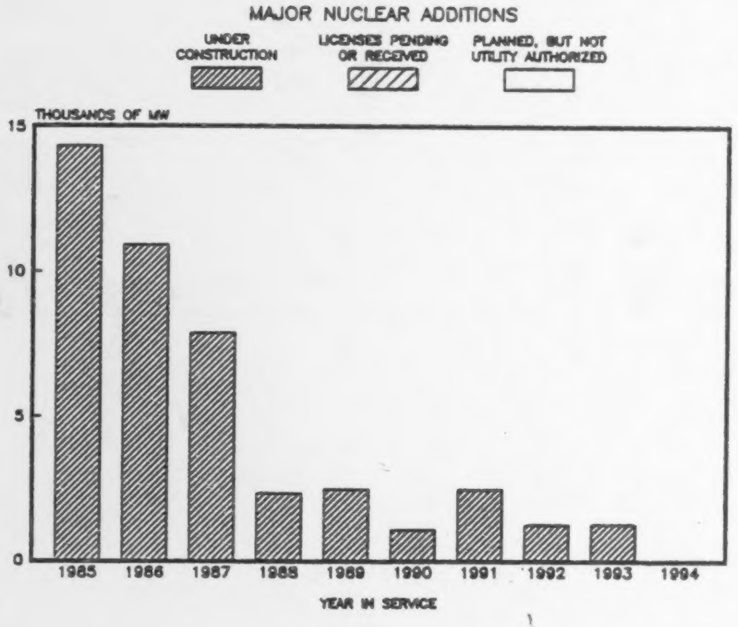
SENSITIVITY BANDS ON
U.S. NET ENERGY FOR LOAD

Figure 3

NERC Load Forecasting Task Force

Figure 4


NERC (U.S.)
MAJOR COAL ADDITIONS
UNDER CONSTRUCTION
LICENSES PENDING OR RECEIVED
PLANNED, BUT NOT UTILITY AUTHORIZED
THOUSANDS OF MW
15
10
5
0
1985
1986
1987
1988
1989
1990
1991
1992
1993
1994
YEAR IN SERVICE


MAJOR NUCLEAR ADDITIONS
UNDER CONSTRUCTION
LICENSES PENDING OR RECEIVED
PLANNED, BUT NOT UTILITY AUTHORIZED
THOUSANDS OF MW
15
10
5
0
1985
1986
1987
1988
1989
1990
1991
1992
1993
1994
YEAR IN SERVICE

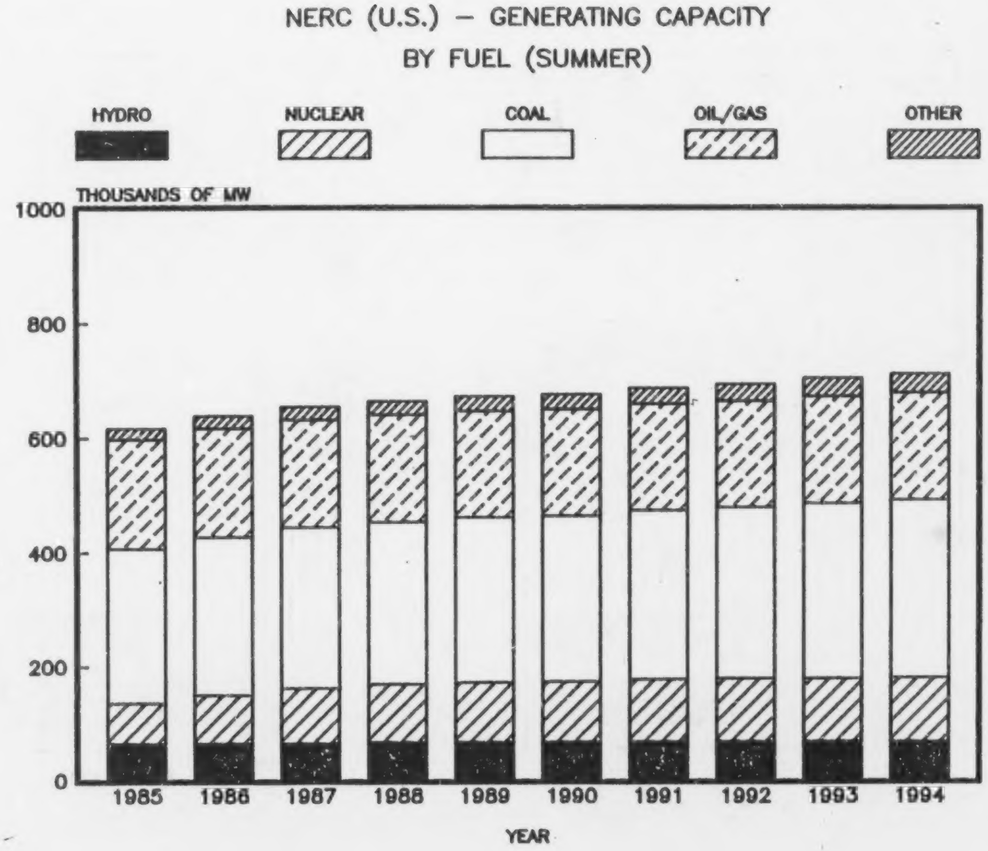
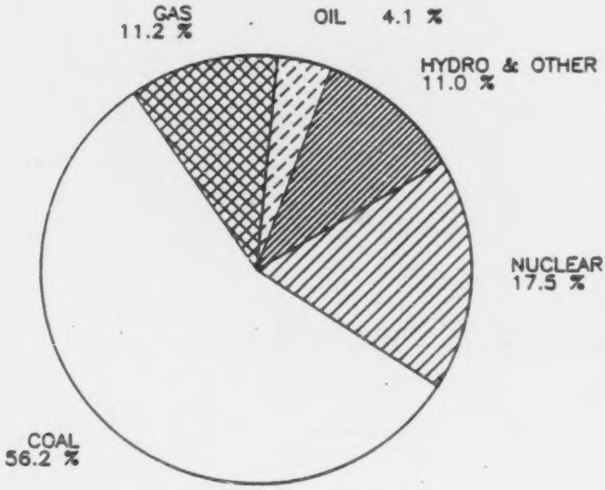

NERC (U.S.) – GENERATING CAPACITY
BY FUEL (SUMMER)
HYDRO
NUCLEAR
COAL
OIL/GAS
OTHER
THOUSANDS OF MW
1000
800
600
400
200
0
1985
1986
1987
1988
1989
1990
1991
1992
1993
1994
YEAR

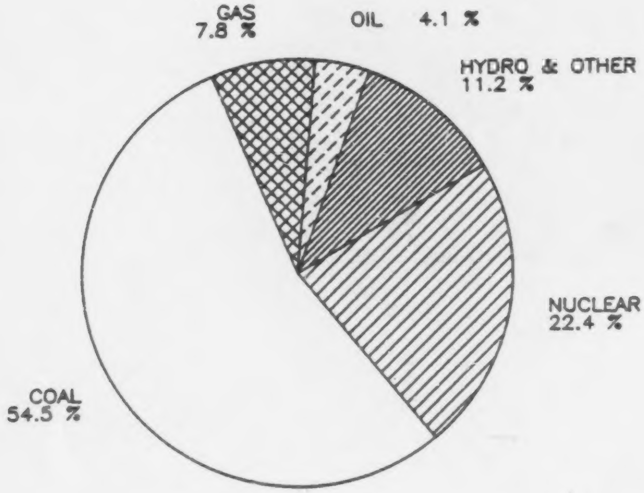
Figure 5

Figure 6

NERC (U.S.) – ELECTRIC GENERATION
BY FUEL



1985
2,448,272 GWh



1994
2,944,891 GWh

Figure 7

1983 Capacity & Demand

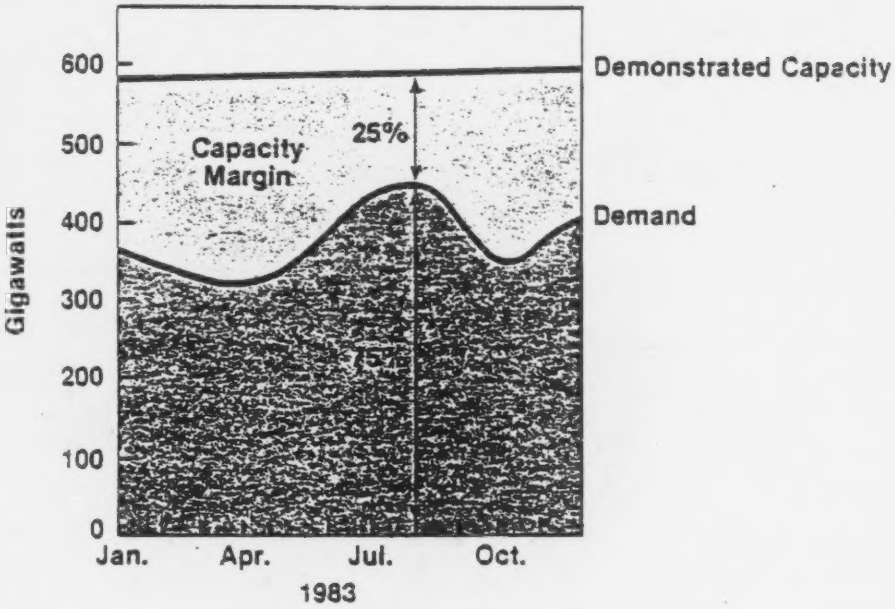


Figure 8

1983 Available Capacity & Operating Margin

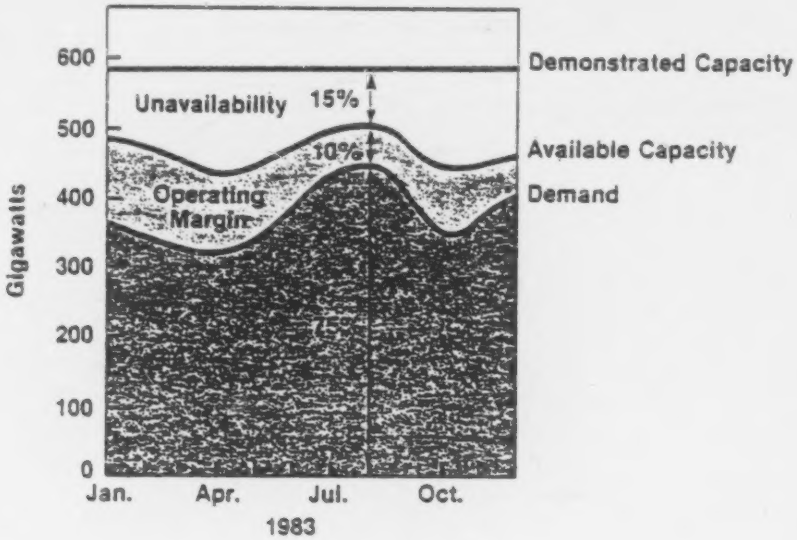
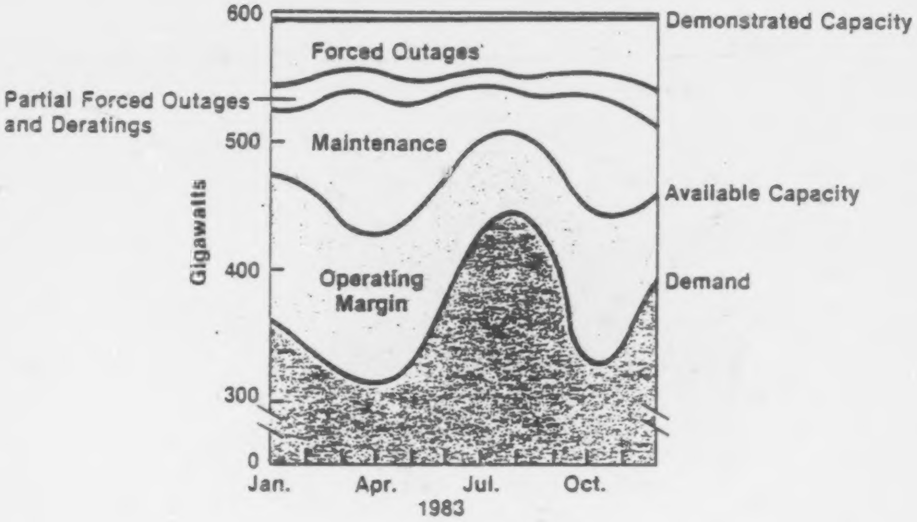


Figure 9

1983 Unavailable Capacity



Measures of Utilization in Other Industries

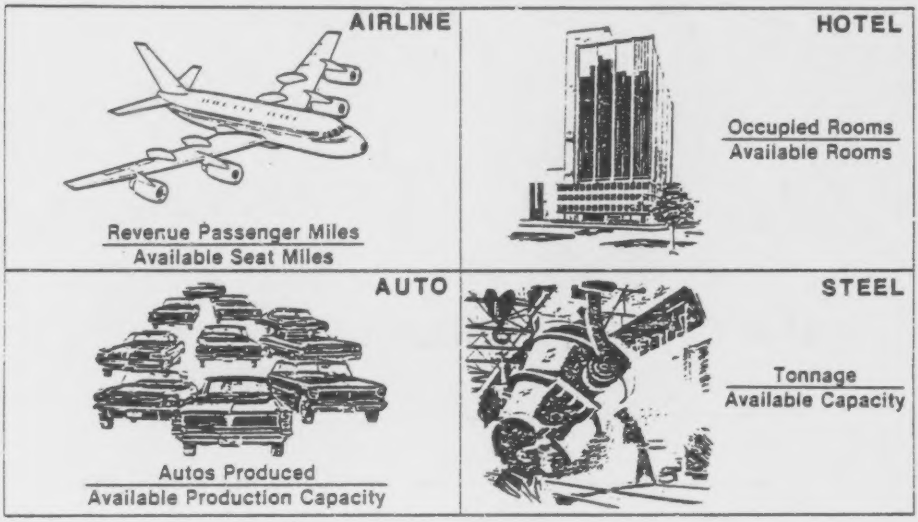

AIRLINE
Revenue Passenger Miles
Available Seat Miles
HOTEL
Occupied Rooms
Available Rooms
AUTO
Autos Produced
Available Production Capacity
STEEL
Tonnage
Available Capacity

Figure 11

1983 Capacity Utilization

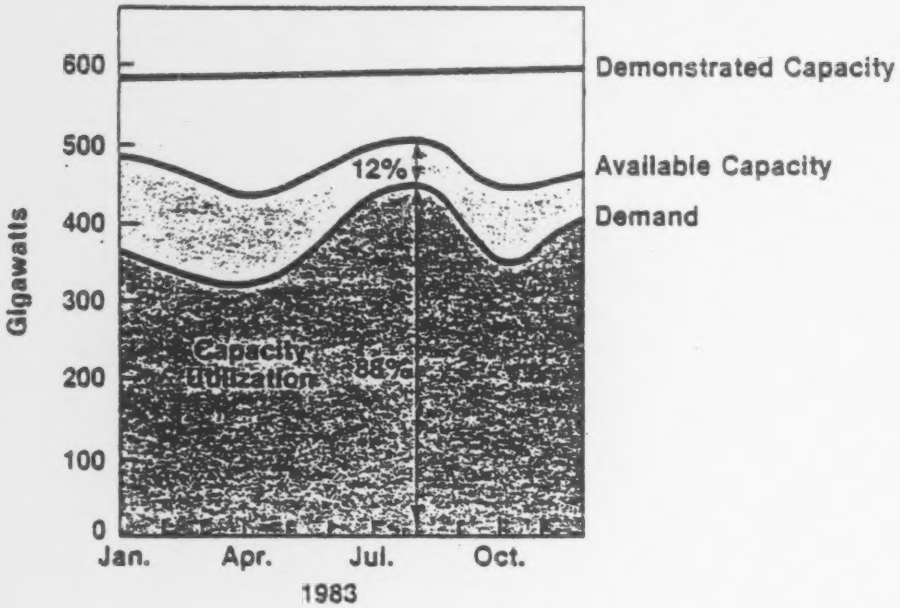
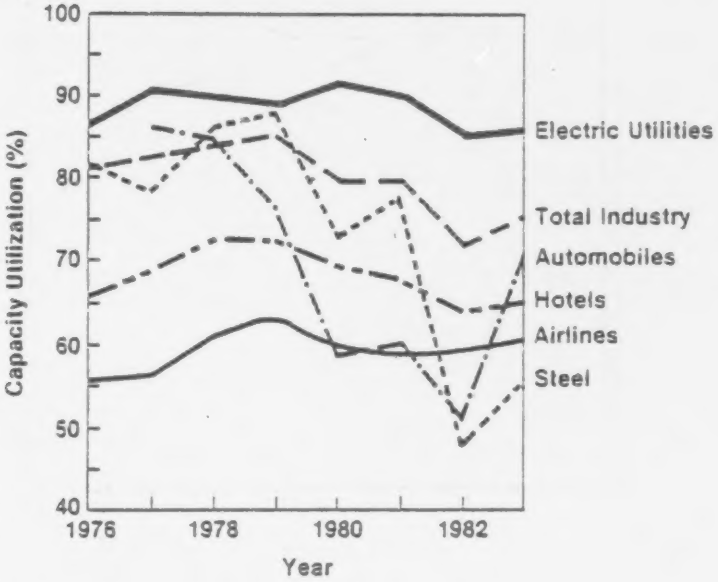


Figure 12

Comparison of Capacity Utilization Rates

1976–1983



SUPPORTABLE PEAK DEMAND vs. CAPACITY PLANNED FOR 1994

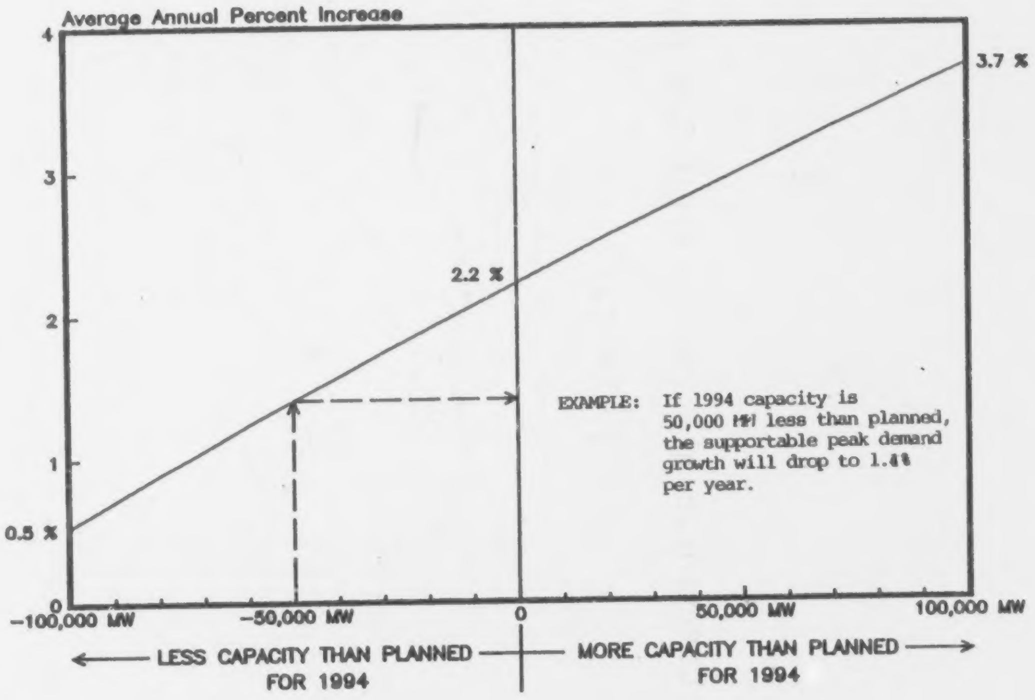
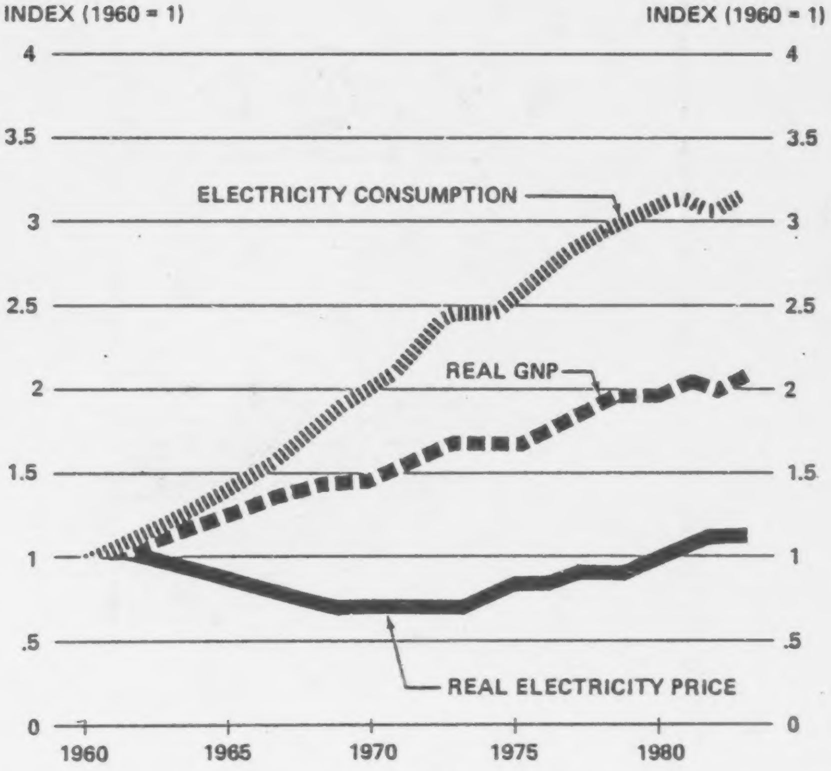


Figure 13

Figure 14

Growth of GNP, Electricity & Electricity Prices



SOURCE: U.S. ENERGY INFORMATION ADMINISTRATION

Figure 15

TOTAL TRANSMISSION UTILIZATION

MAAC and WSCC

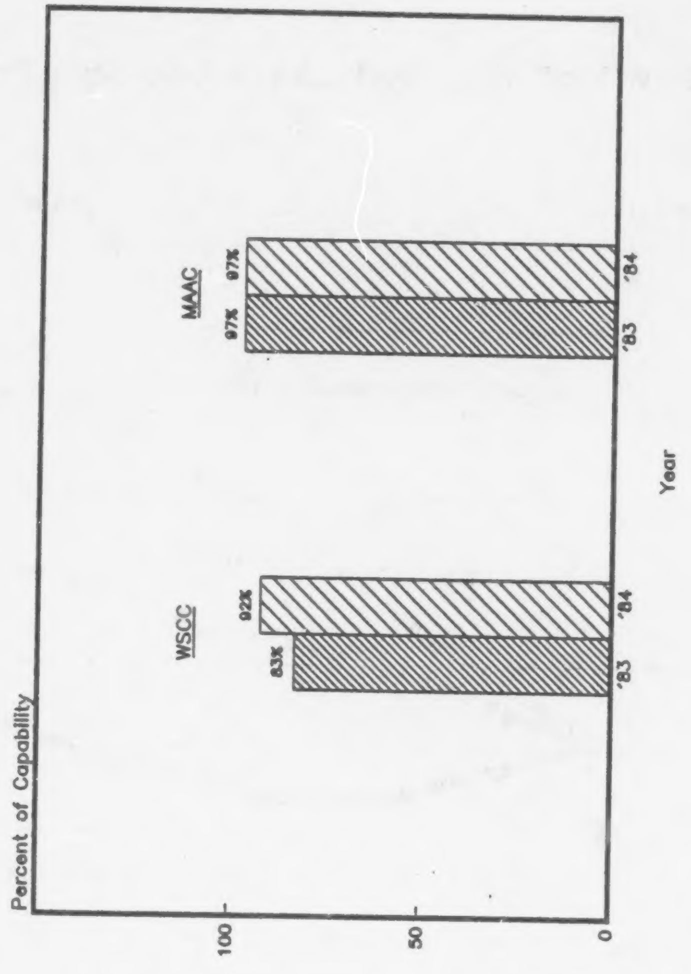
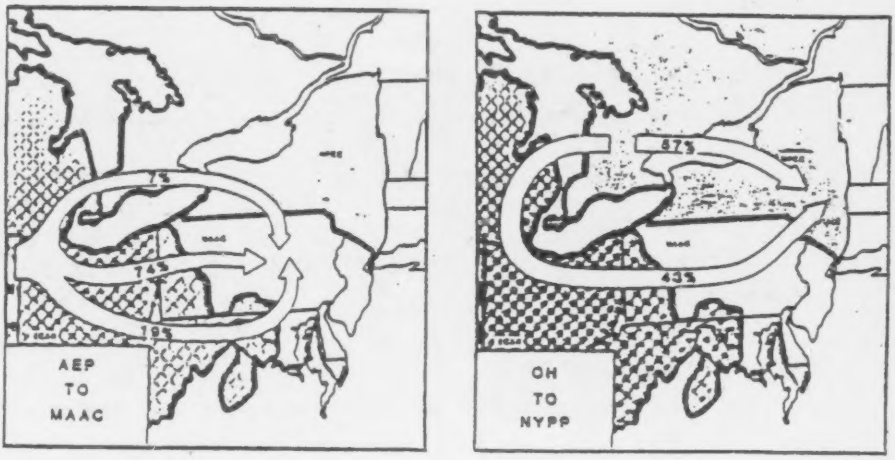


Figure 16

Parallel Path Flow


7%
74%
19%
AEP
TO
MAAC
57%
43%
OH
TO
NYPP

1. **PERSONAL INCOME**

   Excluded: Explains same thing as GNP (the two are closely correlated).

2. **INCOME ELASTICITY**

   Excluded: Income effects adequately captured by GNP variable.

3. **NON-PRICE CONSERVATION**

   Excluded: Assumed to be adequately captured in the base historical series and forecast of load.

4. **GOVERNMENT SPONSORED CONSERVATION**

   Excluded: Assumed to be adequately captured in the base historical and forecast values of load.

5. **OWN PRICE ELASTICITY**

   Excluded as a separate variable: Price effects adequately captured by electricity price variable.

6. **CROSS PRICE ELASTICITY**

   Excluded: This effect was to be captured by the gas price or oil price variables. Ultimately, cross price effects were not included. See following items 7 and 8.

7. **OIL PRICE**

   Excluded: It was judged that price of natural gas was a better substitution proxy, as gas is a much larger direct competitor to electricity.

8. **PRICE OF NATURAL GAS**

   Excluded: Several attempts were made to include gas price in the model, including changing the number of historical observations and using the ratio of real gas price to real electricity price. Each attempt resulted in unreasonable statistical results. The Task Force finally concluded that the variable was not applicable on a national basis.

9. **TECHNOLOGY CHANGE**

   Excluded: Assumed adequately captured elsewhere, mostly in price term and some in mandated conservation which is included in base forecast.

10. **POPULATION**

    Excluded: Model runs demonstrated that population "explains" the same load variations as GNP. As a result, nothing of significance is gained by including a population variable. Also, although population could be substituted for GNP, an unreasonably high load forecast would result.

11. **REAL GNP**

    Included.

12. **REAL ELECTRICITY PRICE**

    Included.

13. **INDUSTRIAL EMPLOYMENT**

    Included as a proxy for sector mix.

14. **WEATHER**

    Included for demand (not for energy).

15. **PRIOR YEAR'S DEMAND**

    Included.

APPENDIX 2

HISTORICAL DATA AND FORECAST VARIABLES

This appendix contains the forecasts of real gross national product, real electricity price, and industrial sector employment used in the analysis, as well as the forecasts of electric energy and peak demand developed using these GNP, price, and employment forecasts. A table listing values for the period 1950-1993, and a plot of values from 1976-1993 is included for each variable. Each plot indicates a 1993 value for each forecast, plus the forecast's average annual compound growth rate for the period 1984-1993.

Historical values of GNP, price, and employment were obtained from published reports by Data Resources, Incorporated. Forecasts of each of these "inputs" represent the arithmetic mean expectation of the analysis team members regarding high, most likely, and low future values of the inputs.

TABLE A-1
SENSITIVITY BANDS ON
NERC U.S. SUMMER PEAK DEMAND (GIGAWATTS)

	HIGH BANDS			LOW BANDS	
	Hot Summer	Cool Summer	NERC Historical	Hot Summer	Cool Summer
1950	65	65	65	65	65
1951	70	70	70	70	70
1952	75	75	75	75	75
1953	81	81	81	81	81
1954	89	89	89	89	89
1955	102	102	102	102	102
1956	106	106	106	106	106
1957	111	111	111	111	111
1958	118	118	118	118	118
1959	125	125	125	125	125
1960	133	133	133	133	133
1961	141	141	141	141	141
1962	151	151	151	151	151
1963	161	161	161	161	161
1964	175	175	175	175	175
1965	186	186	186	186	186
1966	203	203	203	203	203
1967	213	213	213	213	213
1968	238	238	238	238	238
1969	258	258	258	258	258
1970	275	275	275	275	275
1971	292	292	292	292	292
1972	319	319	319	319	319
1973	343	343	343	343	343
1974	349	349	349	349	349
1975	359	359	359	359	359
1976	360	360	360	360	360
1977	387	387	387	387	387
1978	396	396	396	396	396
1979	398	398	398	398	398
1980	427	427	427	427	427
1981	428	428	428	428	428
1982	415	415	415	415	415
1983	448	448	448	448	448

TABLE A-1 (CONTINUED)

	HIGH BANDS			LOW BANDS	
	Hot Summer	Cool Summer	NERC Forecast	Hot Summer	Cool Summer
1984	484	456	447	453	427
1985	507	477	461	447	421
1986	530	499	472	442	417
1987	553	521	485	439	414
1988	577	543	497	438	412
1989	602	567	509	437	411
1990	627	591	521	437	411
1991	653	615	534	437	412
1992	680	641	546	439	413
1993	708	667	559	440	415
Annual Growth (%)					
1984-1993	4.3%	4.3%	2.5%	-0.3%	-0.3%

TABLE A-2
SENSITIVITY BANDS ON NERC U.S.
NET ENERGY FOR LOAD FORECAST (THOUSAND GWh)

	HIGH BANDS			LOW BANDS	
	64% Load Factor	60% Load Factor	NERC Historical	64% Load Factor	60% Load Factor
1950	302	302	302	302	302
1951	343	343	343	343	343
1952	369	369	369	369	369
1953	414	414	414	414	414
1954	443	443	443	443	443
1955	519	519	519	519	519
1956	572	572	572	572	572
1957	602	602	602	602	602
1958	614	614	614	614	614
1959	676	676	676	676	676
1960	737	737	737	737	737
1961	777	777	777	777	777
1962	838	838	838	838	838
1963	897	897	897	897	897
1964	964	964	964	964	964
1965	1,031	1,031	1,031	1,031	1,031
1966	1,122	1,122	1,122	1,122	1,122
1967	1,197	1,197	1,197	1,197	1,197
1968	1,300	1,300	1,300	1,300	1,300
1969	1,412	1,412	1,412	1,412	1,412
1970	1,503	1,503	1,503	1,503	1,503
1971	1,583	1,583	1,583	1,583	1,583
1972	1,702	1,702	1,702	1,702	1,702
1973	1,837	1,837	1,837	1,837	1,837
1974	1,835	1,835	1,835	1,835	1,835
1975	1,872	1,872	1,872	1,872	1,872
1976	1,995	1,995	1,995	1,995	1,995
1977	2,104	2,104	2,104	2,104	2,104
1978	2,176	2,176	2,176	2,176	2,176
1979	2,247	2,247	2,247	2,247	2,247
1980	2,294	2,294	2,294	2,294	2,294
1981	2,318	2,318	2,318	2,318	2,318
1982	2,259	2,259	2,259	2,259	2,259
1983	2,342	2,342	2,342	2,342	2,342

TABLE A-2 (CONTINUED)

	HIGH BANDS			LOW BANDS	
	64% Load Factor	60% Load Factor	NERC Forecast	64% Load Factor	60% Load Factor
1984	2,635	2,470	2,390	2,465	2,311
1985	2,758	2,586	2,471	2,431	2,280
1986	2,883	2,702	2,541	2,408	2,257
1987	3,010	2,822	2,614	2,392	2,242
1988	3,141	3,944	2,685	2,382	2,233
1989	3,275	3,070	2,756	2,378	2,229
1990	3,413	3,200	2,825	2,378	2,229
1991	3,556	3,334	2,896	2,381	2,232
1992	3,703	3,471	2,969	2,388	2,238
1993	3,854	3,613	3,040	2,397	2,247
Average Annual Growth					
1984-1993	4.3%	4.3%	2.7%	-0.03%	-0.03%

TABLE A-3
REAL GROSS NATIONAL PRODUCT ASSUMPTIONS
(Billion $ 1972)

YEAR	HIGH	BASE HISTORICAL	LOW
1950	534	534	534
1951	554	554	554
1952	575	575	575
1953	622	622	622
1954	614	614	614
1955	655	655	655
1956	672	672	672
1957	684	684	684
1958	681	681	681
1959	722	722	722
1960	737	737	737
1961	757	757	757
1962	800	800	800
1963	833	833	833
1964	876	876	876
1965	929	929	929
1966	985	985	985
1967	1,011	1,011	1,011
1968	1,058	1,058	1,058
1969	1,088	1,088	1,088
1970	1,086	1,086	1,086
1971	1,122	1,122	1,122
1972	1,186	1,186	1,186
1973	1,254	1,254	1,254
1974	1,246	1,246	1,246
1975	1,232	1,232	1,232
1976	1,298	1,298	1,298
1977	1,370	1,370	1,370
1978	1,439	1,439	1,439
1979	1,479	1,479	1,479
1980	1,474	1,474	1,474
1981	1,503	1,503	1,503
1982	1,477	1,477	1,477
1983	1,534	1,534	1,534

TABLE A-3 (CONTINUED)

YEAR	HIGH	BASE PROJECTION	LOW
1984	1,576	1,573	1,553
1985	1,628	1,613	1,581
1986	1,682	1,654	1,610
1987	1,738	1,697	1,639
1988	1,795	1,741	1,668
1989	1,854	1,785	1,698
1990	1,915	1,831	1,729
1991	1,979	1,877	1,760
1992	2,044	1,925	1,792
1993	2,111	1,974	1,824
Average Annual Growth			
1984-1993	3.30%	2.56%	1.80%

TABLE A-4
REAL ELECTRICITY PRICE ASSUMPTIONS
(1972 ¢/kWh)

YEAR	HIGH*	BASE HISTORICAL	LOW
1950	3.55	3.55	3.55
1951	3.43	3.43	3.43
1952	3.28	3.28	3.28
1953	3.17	3.17	3.17
1954	3.07	3.07	3.07
1955	2.98	2.98	2.98
1956	2.84	2.84	2.84
1957	2.71	2.71	2.71
1958	2.62	2.62	2.62
1959	2.51	2.51	2.51
1960	2.43	2.43	2.43
1961	2.45	2.45	2.45
1962	2.37	2.37	2.37
1963	2.29	2.29	2.29
1964	2.22	2.22	2.22
1965	2.15	2.15	2.15
1966	2.03	2.03	2.03
1967	1.97	1.97	1.97
1968	1.87	1.87	1.87
1969	1.77	1.77	1.77
1970	1.75	1.75	1.75
1971	1.76	1.76	1.76
1972	1.77	1.77	1.77
1973	1.75	1.75	1.75
1974	2.00	2.00	2.00
1975	2.14	2.14	2.14
1976	2.19	2.19	2.19
1977	2.29	2.29	2.29
1978	2.31	2.31	2.31
1979	2.29	2.29	2.29
1980	2.54	2.54	2.54
1981	2.62	2.62	2.62
1982	2.78	2.78	2.78
1983	2.76	2.76	2.76

TABLE A-4 (CONTINUED)

YEAR	HIGH*	BASE PROJECTION	LOW
1984	2.76	2.79	2.81
1985	2.75	2.81	2.86
1986	2.75	2.84	2.91
1987	2.74	2.87	2.96
1988	2.74	2.89	3.02
1989	2.74	2.92	3.07
1990	2.73	2.95	3.12
1991	2.73	2.97	3.18
1992	2.72	3.00	3.24
1993	2.72	3.03	3.31
Average Annual Growth			
1984-1993	-0.16%	0.92%	1.84%

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*"High" in the case means the price that would yield the highest load.

TABLE A-5
INDUSTRIAL EMPLOYMENT ASSUMPTIONS
(MILLION EMPLOYEES)

YEAR	HIGH	BASE HISTORICAL	LOW
1950	16.5	16.5	16.5
1951	16.8	16.8	16.8
1962	17.0	17.0	17.0
1953	17.6	17.6	17.6
1954	16.3	16.3	16.3
1955	16.9	16.9	16.9
1956	17.3	17.3	17.3
1957	17.2	17.2	17.2
1958	16.0	16.0	16.0
1959	16.7	16.7	16.7
1960	16.8	16.8	16.8
1961	16.4	16.4	16.4
1962	16.9	16.9	16.9
1963	17.0	17.0	17.0
1964	17.3	17.3	17.3
1965	18.1	18.1	18.1
1966	19.2	19.2	19.2
1967	19.5	19.5	19.5
1968	19.8	19.8	19.8
1969	20.2	20.2	20.2
1970	19.4	19.4	19.4
1971	18.6	18.6	18.6
1972	19.2	19.2	19.2
1973	20.2	20.2	20.2
1974	20.1	20.1	20.1
1975	18.3	18.3	18.3
1976	19.0	19.0	19.0
1977	19.7	19.7	19.7
1978	20.5	20.5	20.5
1979	21.1	21.1	21.1
1980	20.3	20.3	20.3
1981	20.2	20.2	20.2
1982	19.0	19.0	19.0
1983	18.9	18.9	18.9

TABLE A-5 (CONTINUED)

YEAR	HIGH	BASE PROJECTION	LOW
1984	19.1	19.0	18.8
1985	19.3	19.0	18.7
1986	19.6	19.1	18.7
1987	19.8	19.2	18.6
1988	20.1	19.3	18.5
1989	20.3	19.3	18.4
1990	20.6	19.4	18.4
1991	20.8	19.5	18.3
1992	21.1	19.6	18.2
1993	21.3	19.7	18.1
Average Annual Growth			
1984-1993	1.22%	0.40%	-0.42%

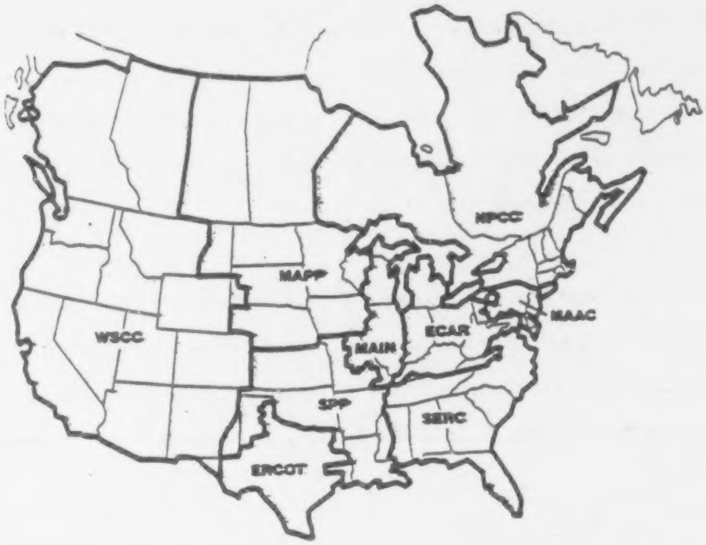
ABOUT THE COUNCIL

The North American Electric Reliability Council had its beginnings in the aftermath of the 1965 Northeast Power Blackout. That occurrence convinced many Industry and Government leaders that the rapidly developing system of interconnected utilities would require additional coordination to reestablish reliability and to prevent such widespread blackouts from occurring again.

The result was the formation of the Electric Council by the electric utility industry in 1968. The Council is made up of nine Regional Councils whose member utilities account for virtually all of the electric power supply in the contiguous United States and seven bordering provinces of Canada. The Alaska Systems Coordinating Council is an affiliate member.

A Council Map is attached.

North American Electric Reliability Council



ECAR
East Central Area Reliability Coordination Agreement

ERCOT
Electric Reliability Council of Texas

MAAC
Mid-Atlantic Area Council

MAIN
Mid-America Interpool Network

MAPP
Mid-continent Area Power Pool

NPCC
Northeast Power Coordinating Council

SERC
Southeastern Electric Reliability Council

SPP
Southwest Power Pool

WSCC
Western Systems Coordinating Council

AFFILIATE

ASCC
Alaska Systems Coordinating Council

The North American Electric Reliability Council (NERC) was formed by the electric utility industry in 1968 to promote the RELIABILITY of bulk power supply in the electric utility systems of North America. NERC consists of nine Regional Reliability Councils and one affiliate encompassing virtually all of the power systems in the United States and Canada.

RELIABILITY, in a bulk power electric system, is the degree to which the performance of the elements of that system results in power being delivered to consumers within accepted standards and in the amount desired. The degree of reliability may be measured by the frequency, duration, and magnitude of adverse effects on consumer service.

Bulk power electric system reliability can be addressed by considering two basic and functional aspects of the bulk power system—adequacy and security.

ADEQUACY is the ability of the bulk power electric system to supply the aggregate electrical power and energy requirements of the consumers at all times, taking into account scheduled and unscheduled outages of system components.

SECURITY is the ability of the bulk power electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system components.

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COUNCIL PUBLICATIONS

Reliability Assessment Reports:

- 1985 Reliability Review (September 1985)
- Electric Power Supply and Demand 1985-1994 (July 1985)
- 1985 Summer Assessment (May 1985)
- 1984/85 Winter Assessment (November 1984)

Generating Availability Data System Reports:

- Equipment Availability Report for 1983
- Equipment Availability Report for 1974-1983
- Component Cause Code Report for 1974-1983

Special Reports and Reference Documents:

- Overview of Reliability Criteria Among the Regional Councils (December 1982)
- Reliability Concepts (February 1985)
- Transfer Capability (October 1980)
- Impediments to Transfers (May 1984)
- Impediments to Transfers: An Update (June 1985)
- Review of Major Disturbances (May 1985)
- Generating Capacity in U.S. Electric Utilities: An Update* (December 1984)

*An EPRI Report co-authored with NERC.

Senator EVANS. Thank you very much.

Dr. Beyea.

STATEMENT OF DR. JAN BEYEA, SENIOR STAFF SCIENTIST, NATIONAL AUDUBON SOCIETY

Dr. BEYEA. Thank you. I'll summarize the essence of my testimony.

Future demand for electricity in the United States is uncertain, as we've heard today. It's so uncertain that it would be imprudent for the average utility to plan to build any more large-scale baseload powerplants, other than those already in construction, for at least the rest of the century.

Some of the reasons why there's uncertainty have already been mentioned today. First, there's uncertainty in the future price of electricity and its competing fuels. There's also uncertainty in the future rates of economic growth.

Some things that haven't been mentioned: Obviously there are uncertainties in forecasting models themselves. And even if the future price of electricity and behavior of the economy were known perfectly, forecasting models would still be unable to predict consumption accurately.

And, finally, there's uncertainty in Government policy. There's uncertainty about what's going to happen to appliance standards. There's uncertainty about what local regulators are going to do about phasing in nuclear plants, and there's uncertainty about overall pricing policy which is now in a state of flux.

How important are these effects? Table 1 at the end of my statement shows an attempt to quantify part of the uncertainty, using the detailed computer model that we developed for the 1984 Audubon Energy Plan.

In 1995, the spread in demand of plus or minus 17 percent results when input parameters such as price, growth and elasticity variables are varied over reasonable ranges. And this spread in projected consumption does not even take into account uncertainty in Government policy.

In terms of percentage growth per year, the table indicates a rate ranging from minus 0.5 percent to plus 2.3 percent per year. The mid-range growth value is 1 percent per year in utility electricity. To put that in more context with other studies, if you threw out the cogeneration projection, that would raise this about a half percentage point to 1.5 percent, and probably if you used similar assumptions about the mix of GNP between commercial and industry, you add another 0.3 percent.

Also, if you use the same price assumptions that EIA used earlier, you also get the higher projection.

The significance of the table is that a positive increase in demand for electricity cannot be considered firm. We looked at back issues of the electrical industry magazine, Electrical World, which has been making electricity forecasts for 35 years. How well have they done? The results, averaged over 35 years, indicate for 10-year forecasts, an average overestimate of 11 percent. Now, I don't think that's too bad, but it does have a significant impact, if that's true, on how one should derate current forecasts. And if

Electrical World's current 1995 demand forecast is derated by the appropriate factor to account for their tendency to overestimate, their growth projection falls to a modest level corresponding to 1.8 percent growth per year.

In table 3 at the end of my testimony, I have used a statistical analysis of Electrical World's past forecasts to obtain an estimate of the uncertainty in their current forecasts. For 1995, the range of uncertainty is a low of 0.7 percent per year to a high of 3.3 percent per year. The mid-range value is the number I stated earlier—1.8 percent per year.

Now, how easily will utilities be able to meet this range of demand? I show in my written testimony—and there's been a lot of testimony to that effect today—that the electric industry will have no difficulty in meeting the component of baseload demand that we consider firm, even if one takes that as about 1 percent per year increase out to the year 2000.

How should utilities plan to meet the component of demand that is uncertain? Ideally, as people have said, they should rely for backup on strategies which have short lead times and which can be implemented in small increments of power. And there, as you've heard, available many low-cost options that offer short lead times—upgrading of older plants to increase efficiency, extend lifetimes—we've heard about that—cogeneration we all heard about.

I'd like to also mention offpeak wheeling of power among utilities, and finally demand reduction using such strategies as marginal cost pricing and financing of residential and commercial electricity conservation technologies.

Unfortunately, if implemented under regulatory rules now in place in most States, these measures would prevent utilities from growing as they would like or making as much money for their stockholders as they have traditionally. Clearly, the regulatory rules of the game need changing so that utilities can make a good profit in a changed electricity world—a world where reducing demand through technological improvements is cheaper than increasing central station supply.

In my written statement I've mentioned a number of ways that this can be accomplished.

Before concluding, I want to briefly mention some concerns we have about proposals to increase imports of Canadian electricity. National Audubon does not want to see the United States export its environmental problems to Canada through excessive reliance on electricity imports. There are real problems with expansion of Canadian capacity that will not get adequate environmental review, especially in Canada's last frontier, its undeveloped north.

Canadian laws on project review are much weaker than U.S. laws. What is needed is a requirement in U.S./Canadian power contracts that new producing facilities undergo an American-style environmental review.

That concludes my summary statement. Thank you.

[The prepared statement of Dr. Beyea follows:]

Dealing with Uncertainties in Projections of Electricity Consumption

Statement by
Dr. Jan Beyea
Senior Staff Scientist
National Audubon Society
(212)-546-9300

before the
Senate Committee
on
Energy and Natural Resources

July 25, 1985

Future demand for electricity in the United States is so uncertain that it would be imprudent for the average utility to plan to build any more large-scale, baseload power plants (other than those already in construction) for at least the rest of this century.

Utilities should plan to meet the uncertain portion of demand by helping to finance electricity conservation efforts and by relying for backup on supply technologies that can be built on relatively short notice. Using such a strategy, utilities could minimize expected costs to the consumer. Less coal pollution and less nuclear waste would be produced.

Uncertainties in electricity projections arise for a number of reasons, including:

a) uncertainty in the future price of electricity and its competing fuels. The future price of electricity can only be estimated approximately, which means that its corresponding impact on future consumption can only be estimated approximately. Similar considerations hold in connection with oil prices. For instance, if the future price of oil is higher than forecasters assume, more energy users will shift to electricity. On the other hand, if the price of oil should turn out to be lower than forecasters assume, the reverse will be true, leading to reduced consumption of electricity. Certainly, electricity forecasters cannot be expected to predict the future price of oil, so it is no reflection on their abilities to say that their forecasts are inherently uncertain.

b) uncertainty in future rates of economic growth. Since most forecasting models link--in one way or another--electricity consumption to economic growth, uncertainty in the future behavior of the economy causes uncertainty in electricity projections. Just as forecasters cannot be expected to predict future energy prices, they cannot be expected to predict future economic growth with any certainty.

c) uncertainty in forecasting models themselves. Even if the future price of electricity and behavior of the economy were known perfectly, forecasting models would still be unable to predict consumption accurately. Even the most sophisticated of forecasting models depends on coefficients and structural parameters that are uncertain. In some cases, particularly when it is necessary to quantify long-run changes in technology, parameters are obtained by making guesses that seem reasonable to the analyst. In other cases, values of key parameters can be extracted from past data on energy consumption, but it is rare that any such analysis can give precise numbers. This is true particularly when it comes to estimating long-run response to price changes ("elasticity" parameters).

d) uncertainty in government policy. Forecasters must make assumptions about government policy in order to project future consumption. For instance, most current forecasts assume that no efficiency standards for home appliances will be promulgated. Yet, the Courts have just struck down the Department of Energy's refusal to implement serious appliance standards,/1/ making the situation uncertain from a forecasting perspective. Federal appliance standards could be expected to reduce 1995 electricity consumption by three percent./2/

In addition to making assumptions about actions taken by federal agencies, forecasters must second-guess local regulatory bodies, whose actions can have major impacts on electricity demand. For instance, if utility commissions decide to phase in gradually the cost of new, expensive nuclear plants, the so-called "rate shock" from these plants will be softened. As a result, consumers will not cut back as much on consumption as they would otherwise.

Finally, forecasters have to recognize that overall pricing policy for electricity is in a state of flux. For instance, the Federal Energy Regulatory Commission (FERC) is now hinting that "major changes in pricing and cost allocation may be in store"./3/ One possibility that FERC is examining is marginal cost pricing. Should this type of pricing be implemented nationally, we have estimated that by itself it could reduce 1995 consumption by 10%./4/ How important are these effects? Table 1 shows an attempt to quantify part of the uncertainty in electricity projections for the years 1990, 1995, and 2000 using the detailed computer model developed for the 1984 Audubon Energy Plan./5/ For 1995, a spread of plus/minus 17% results when input parameters, such as price, growth, and elasticity variables are varied over reasonable ranges. The resulting spread in projected consumption shown in the Table, which does not even attempt to take into account uncertainty in government policy, is very broad. In terms of percentage growth per year, the Table indicates a rate ranging from -0.5 to +2.3% per year. The mid-range value is 1.0% per year.

The significance of Table 1 is that, although 1995 demand can be projected to be somewhere between -5% to 29% higher than 1984 consumption under a business-as-usual scenario, a positive increase cannot be considered "firm." According to these projections, if the average utility commission allows its utilities to build any more large, expensive baseload powerplants between now and the year 2000, utilities may find themselves in the same fix they find themselves today, with abnormally high baseload capacity and with excess costs that have to be picked up by their customers.

Additional evidence supporting the thesis that projections of electricity demand are uncertain can be obtained from the actual record that forecasters have achieved. For instance, the electrical industry magazine, Electrical World, has been making electricity consumption forecasts for 35 years. How well have they done? With the help of my associate Michael Case, we have gone back into the historical record and compared Electrical World's past projections with actual consumption. As shown in Table 2, we found that projections they made in the 50's tended to underestimate actual consumption, whereas projections they made in the 60's and 70's tended to overestimate consumption. Also shown in the Table is an average of their performance record over the years in which they made forecasts. The results indicate for ten-year forecasts an average overestimate of 11%.

The tendency for the electrical industry to overestimate demand is well known. If Electrical World's current 1995 demand forecast of a 36% increase over 1984 demand is derated by the appropriate factor to account for their tendency to overestimate, their growth projection falls to a more modest 22% increase. As a result of this correction, I consider a 22%-increase (1.8% growth per year compounded) to be as reasonable a mid-range estimate for 1995 demand under business-as-usual conditions as Audubon's mid-range projection. (I will discuss later how even this growth can be decreased through changes in state and federal energy policy.)

It is interesting to note that Electrical World does not include much cogeneration in its forecasts. If the cogeneration component of the Audubon projection is assigned to utility generation, the resulting mid-range figures for utility demand are quite close to the derated values obtained from the Electrical World data.

The most important lesson to be drawn from Table 2 is not that 10-year industry forecasts should be derated, but that the range of the discrepancy between forecast and actual consumption in individual cases can be very large. The numbers in Table 2 range from a 10% underestimate to a 36% overestimate.

Table 3 shows how a statistical analysis of Electrical World's past forecasts can be used to obtain an estimate of the uncertainty in their current forecasts. The uncertainty range shown in the Table is similar to the range that was calculated in Table 1 by varying price, growth, and elasticity variables in the Audubon model.

From the proceeding analysis, it can be seen that both theoretical and statistical evidence supports the idea that a large uncertainty must be assigned to 1995 electricity forecasts.

Meeting firm demand

The electricity industry will have no difficulty in meeting the component of baseload demand that is firm in the derated Electrical World forecast (~~15~~ 22% increase by 2000). Utilities already have a large excess of baseload capacity. They could absorb (on average) an 18% baseload demand increase without adding new plants to the grid./6/ Furthermore, a considerable number of plants currently under construction will be coming on line in the next six years, making the capacity situation even more secure. In fact, new capacity will cause a 12% increase in the nation's electricity supply by 1990, even assuming the cancellation of another 15 or so nuclear plants./7/ The bottom line is that utilities will be able to meet projected firm demand out to the year 2000 with existing plants and those that will soon come on line.

Meeting the uncertain portion of demand projections

How should utilities plan to meet the component of demand that is uncertain? Ideally, they should rely for backup on strategies which have short lead times and which can be implemented in small increments of power. In this way, utilities will be able to respond flexibly to the actual demand situation as it unfolds.

Ironically, there are available so many low-cost options that offer short lead times and small increments that utilities are faced with an embarrassment of riches. Options include

- o upgrading of older plants,
- o cogeneration,
- o off-peak wheeling of power among utilities,
- o demand reduction using such strategies as marginal cost pricing and financing of residential and commercial electricity conservation technologies.

I say these options are an "embarrassment" because, if implemented under regulatory rules now in place in most states, these measures would prevent utilities from growing as they would like or making as much money for their stockholders as they have traditionally.

I must confess, that were I a utility executive with responsibility to my stockholders, I, too, would have no choice in most states but to avoid long-term reliance on demand-reducing conservation options and non-utility cogeneration, even though I knew they would form the lowest-cost mix for my customers. I would recognize that under current rules, a utility needs large capital investments per Kwh to show large profits. None of the options mentioned earlier meet this capital criterion under standard commission rules.

Clearly, the regulatory rules of the game need changing so that utilities can make a good profit in a changed electricity world--a world where reducing demand through technological improvements is cheaper than increasing central-station supply.

The regulatory rules need changing so that the most economical solution for the customer is also the most profitable solution for the utility stockholder. National Audubon supports such changes and is willing to testify before utility commissions as to their merits. Particularly important are steps that would:

- encourage utility commissions throughout the country to allow utilities to put into their rate base any investments in residences and commercial establishments made on behalf of customers that save electricity at less cost than the utility can supply it.
- increase the rate of return for utility-owned cogeneration facilities. This would be appropriate when such investments would lead to lowest cost electricity to the consumer and when utilities chose to put the cogeneration facility into the rate base rather than attempt to operate under PURPA. Such a change in policy will maximize, according to our studies, the use of cogeneration.

  Alternatively, the rate of return that utilities receive for all investments could be raised once the utility signs contracts for a stated amount of cogeneration. (California has already implemented a policy of this sort.)

It seems to me that it is time for all of the actors in the energy debate to break away from their traditional mindsets and negotiate a new set of rules. It is time for utilities to reconsider their insistence that large, central station power plants are the only hope of the economy. And it is time for those of us who criticize utilities for not following a "least-cost" path to recognize that utilities must make money for their stockholders or they are going to fight with all their political power to stop the innovations that we want to see introduced.

California's experience demonstrates that there is an abundance of non-utility PURPA-power out there, which, at least in that state, is sufficient to meet future growth. California's problem is not a shortage of non-utility power but an over-abundance. For instance, the California Energy Commission notes that utiities in its state have signed contracts with PURPA producers for 13,000 megawatts of power. This amount far exceeds the 5,000 megawatts of growth projected for 1995./8/

However, California's good fortune did not arise overnight. The California Utility Commission and the California Energy Commission have had 10 years to discipline their utilities. Do we have to wait 10 years in other states? Compromise and negotiation may well offer a quicker resolution than trying to drag all utilities to the California solution.

Disallowance of imprudent investments

I do not mean to imply by mentioning compromise that utilities should be forgiven for imprudent investments made in the past. Overestimates in demand were so gross that utility commissions must disallow some portions of these investments from being passed on to customers--otherwise the integrity of the regulatory system will be weakened. Utilities will quickly forget about the dangers of overbuilding, should 100% of these unnecessary plants be included in the rate base.

I realize that utilities are claiming that disallowance will make them so risk averse that they will refrain from building new, large baseload power plants until the demand is absolutely certain. Presumably, this is meant as a threat to utility commissions. But it's not a threat at all. It's an indication that utilities haven't yet learned their lesson. They don't yet understand that they should never build large plants until demand is firm.

Even though I believe that disallowance of imprudent investments is essential to preserve the integrity of the regulatory process, I believe that utility commissions across the country should revise their rules so that utilities can make money from demand reduction. Utilities should be allowed to recoup their losses from past imprudent investments as soon as they become willing partners in energy conservation and cogeneration. One strategy capable of providing early relief would be to reduce the disallowance penalty upon good faith evidence that utilities were moving expeditiously to support conservation and cogeneration.

Gas turbines

Some utilities are claiming that, if they don't get to build large power plants, they will be forced to rely on expensive gas turbines. (Gas turbines, although cheap and quick to build, consume expensive fuel.) However, gas turbines are not the only alternatives to large coal plants that can be put into operation quickly. Upgrading existing plants, building cogeneration facilities, financing conservation, and installing advanced turbines are cheaper alternatives. In any case, even if gas turbines were the only alternative to baseload electricity from coal or nuclear power, it would still be wiser for utility commissions to insist that utilities rely on gas turbines to meet any increases in consumption above firm forecasts, unless commissions are going to be very tough on disallowing imprudent investments. From a naive economic perspective, it probably wouldn't make too much difference whether utilities erred on the side of underbuilding large plants or overbuilding them. In both cases, electricity costs would be higher than would be the case if utilities could predict demand exactly. Consider the underbuilding case. If utilities built too few coal and nuclear plants, they would run gas turbines for a few years until they could correct the situation by building extra coal plants. On the other hand, if they overbuilt, they could, in principle, halt or scrap large plants partially under construction as soon as the demand trends were obvious. In this way, they wouldn't waste money on completing plants that were not going to be needed.

I did some simulations of these two theoretical scenarios and found that, in either case, the cost to the customer need not be enormous even for large uncertainties in forecasting. (The reason that the situation need not get out of hand even when demand is highly uncertain is that utilities can make new forecasts each year, with the result that they can constantly update their construction plans to account for changes in consumption trends.)

However, the two situations--overbuilding vs. underbuilding of large plants--are vastly different when it comes to the real world. There are tremendous temptations for utilities to try to get a partially-constructed plant completed and into the rate base. Utilities would be very reluctant to scrap such plants because of potential bad publicity and because utility commissions might require utility stockholders to bear the brunt of the loss, not the ratepayers. Far more tempting would be a strategy of completing the plants, even though not needed, so the plants could legally be charged to the customers in the rate base. Unless utility commissions were tough on allowing such unneeded plants into the rate base, this strategy would probably be in the best interest of the stockholders.

We are seeing the fruits of such temptations around us today in the excess capacity that utilities now have. It is time to stop tempting them by requiring utilities to build only as many large plants as are needed to meet the low end of the demand forecast range.

Additional recommendations

There are a number of important steps, in addition to those already mentioned, that should be taken to ensure that utilities can meet their obligations both to their stockholders and their customers:

- encourage states and regions 1) to implement least-cost electricity planning modelled after the Northwest Power Planning Council's approach, and 2) to enact building codes that require energy efficiency measures that are cost effective for the residents.
- encourage utility commissions to adopt marginal cost pricing.
- encourage the Department of Energy to adopt meaningful appliance standards as it responds to the latest court decisions.
- enact legislation that will require utilities to wheel power off peak through their districts to neighboring utilities. (Current rules on wheeling are too weak to be effective.) Although requiring utilities to wheel power during peak transmission times can unduly burden utilities without

careful consideration of tariffs, the wheeling of off-peak power causes minimal burdens and should be implemented immediately. Off-peak wheeling would go a long way toward eliminating local shortages of baseload power.

Potential for reducing demand for utility power

In order to demonstrate the huge potential for reducing demand for conventional utility power, I draw your attention to Figure 1 which has been taken from the Audubon Energy Plan. It shows what could be accomplished by a commitment to conservation policy by government--a commitment similar to that which California has demonstrated over the last ten years. The graph shows that a high growth forecast under business-as-usual conditions could be converted to a declining growth forecast.

Imports of Canadian electricity/9/

The National Audubon Society and other environmental groups are interested in stimulating electricity conservation because we believe that excess construction of generating capacity unnecessarily burdens the environment. But that does not mean that we support every measure that would reduce the need for central-station plants in the United States. For instance, National Audubon does not want to see the United States export its environmental problems to Canada through excessive reliance on electricity imports.

Energy produced beyond America's northern boundary is beyond the obvious scope of American environmental impact review laws, and beyond meaningful environmental review as well. Author Fred Powledge noted in his November, 1984 article in Audubon magazine that, under the 1973 Canadian Environmental Assessment and Review Process:

> there is no power to subpoena witnesses, no sworn testimony. The developers of projects - government departments, corporations, individuals - write their own environmental impact statements, and the federal panel that reviews these projects is empowered only to send its conclusions along to the minister of the environment, who is under no compulsion to follow them./10/

Canada's environmental movement has its work cut out for it. Unlike American law, Canadian law also requires that plaintiffs unsuccessfully bringing suit must be prepared to pay a portion of their opponent's costs. This aspect of Canadian law, along with limitations on judicial review, and shortages of private funding, present substantial obstacles to the success of environmental groups in Canada./11/

These difficulties, along with the absence of meaningful Canadian environmental impact review requirements, mean that proposed projects such as Alberta's controversial Slave River hydropower project may proceed without an impartial assessment of their impact, or their need. This proposed nine-billion-Kwh project is under consideration while excess Canadian capacity available for export -- over half of it produced by hydropower facilities -- is estimated to lie in the 10,000 to 20,000 Mw range for the 1990's./12,13/ Serious questions abound regarding the demand for the additional power Slave River would produce and the capacity of U.S.-Canadian inter-ties to carry it./14/ Under current environmental laws in Canada, such questions may never be seriously pursued. If not, the result will be a loss to Canada's wild lands, and to American utilities working to compete against cheap imported power.

Canadian imports help some U.S. utilities meet emergency demand, and they serve to encourage domestic power producers to temporarily supplant costly oil-fired generating plants with import power./15/ Nevertheless, there is a real problem with unreviewed expansion in Canadian capacity, especially in Canada's undeveloped North. In an official report of a royal commission named to look into the consequences of a proposed pipeline in the Mackenzie River Valley, Vancouver Judge Thomas Berger explained:

> we are now at our last frontier. It is a frontier that all of us have read about, but few of us have seen.... The decisions we have to make are not, therefore, simply about northern pipelines. They are decisions about the protection of the northern environment and the future of northern peoples./16/

The benefits of current imports would not be foregone if the U.S. were to place greater emphasis on environmental review of new Canadian projects designed to produce power for export. More stringent review could be accomplished through stipulations on U.S.-Canadian power contracts requiring new producing facilities to undergo an American-style environmental review. This way, Canada's natural resources would be better protected, and U.S. utilities competing with cheaper foreign power would find themselves on more advantageous footing with their Canadian counterparts.

Footnotes and References

1) Natural Resources Defense Council v. John S. Herrington, No. 83-1195, slip op. (D.C. Circuit, July 16, 1985)

2) Audubon Energy Plan, National Audubon Society, 950 Third Avenue, NY NY 10022, Vol II (1984), Table C-9.

3) As reported in BNA´s Energy Report, Bureau of National Affairs, Inc., Washington, D.C., 13, 642

4) Audubon Energy Plan, Vol I, Table 9, pg. 32

5) In addition to ref. 2, see, L.R. Medsker, "An interactive decision support system for energy policy analysis," Communications of the ACM, 27, 1122-1128 (1984)

6) "35th Annual Electrical Utility Industry Forecast," Electrical World, Sept. 1984, as evident in Table, pg. 53.

7) Based on capacity forecast from Electrical World, Ibid, Table at pg. 55.

8) 1985 Biennial Report, California Energy Commission, Sacramento

9) This section was prepared in collaboration with Michael Case.

10) Fred Powledge "Saving An Eden Called Canada Is A Task As Big As The Land", Audubon, November, 1984, pg. 86.

11) Ibid at pg. 89, 96.

12) Kaufman, A.; Dulchinos, D.; and Parker, L., "Gold At The End Of The Rainbow?: A Perspective On The Future Of The Electric Utility Industry", Congressional Research Service (Dec., 1984), pg. 104. (Citing: North American Electric Reliability Council).

13) Ibid at pg. 103.

14) Ibid at pg. 106.

15) Ibid at pg. 100.

16) Thomas R. Berger, Northern Frontier, Northern Homeland: The Report of the Mackenzie Valley Pipeline Inquiry, 1977.

Table 1

Uncertainty in Projections of Utility Electricity Demand That Arise From Uncertainties in Price, Economic Growth, and Model Parameters.

	Increase over 1984 in utility production of electricity, as projected by the Audubon Model a),b)			% Growth Per Year		
Year	Low	Mid	High	Low	Mid	High
1990	-4%	3%	10%	-0.7%	0.5%	1.6%
1995	-5	12	29	-0.5	1.0	2.3
2000	-2	22	46	-0.1	1.2	2.4

---

a) Two projections were given in the Audubon Plan, one using a model calibrated against industry and DOE projections, and one calibrated against projections made by William W. Hogan of Harvard and Robert Williams of Princeton. The results shown here are an average of the results obtained with the two models.

b) Electricity produced in cogeneration facilities is not included. 1984 consumption is taken to be 8.7% higher than the 1980 consumption figures cited in the *Audubon Energy Plan* [see *Monthly Energy Review*].

Table 2

Historical Forecasting Record of the Electrical Industry Magazine, Electrical World

Year Forecast Made		Year of Forecast	% Ratio of Forecasts to Actual Consumption	Average Ratio	Standard Deviation
5 Yr. Forecasts					
1955	--	1960	98.2 %		
1960	--	1965	105.4		
1965	--	1970	94.8	105.2 %	± 8 %
1970	--	1975	116.2		
1975	--	1980	111.6		
10 Yr. Forecasts					
1955	--	1965	96.4 %		
1960	--	1970	105.9		
1965	--	1975	105.5	111.1 %	± 15.2 %
1970	--	1980	136.5		
15 Yr. Forecasts					
1955	--	1970	90.5 %		
1960	--	1975	123.0	110.7 %	± 14.4 %
1965	--	1980	1[illegible]8.5		

Table 3

Adjustments to Projections by Electrical World to Account for Past Errors in Forecasting

(Increases in Consumption Over 1984 Levels)

Year	Raw Numbers a)	Derated Numbers b),c)			% Growth Per Year c),d)		
		Low	Mid	High	Low	Mid	High
1990	20 %	6	14	24 %	1.0	2.2	4.3 %
1995	36 %	8	22	43 %	0.7	1.8	3.3 %
2000	53 %	22	27	59 %	1.2	2.0	2.9 %

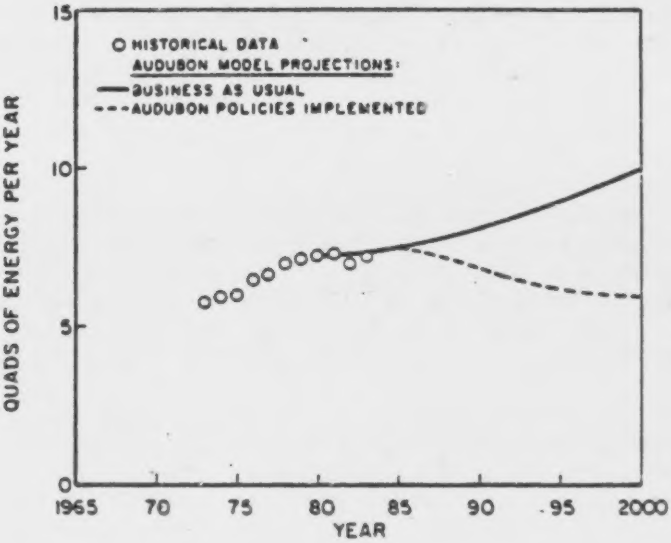
---

a) Referenced against 1984 as base year. Adapted from, "35th Annual Electric Utility Industry Forecast," Electrical World, September 1984, Page 49.

b) Previous column derated by overestimates calculated in Table 2.

c) Low and High projections represent one standard deviation from the Mid figure.

d) Previous column converted to average annual growth.



Projection of Future Demand for Utility Electricity

Senator EVANS. Thank you very much.
Dr. Naill.

STATEMENT OF DR. ROGER F. NAILL, VICE PRESIDENT, ENERGY PLANNING SERVICES, APPLIED ENERGY SERVICES, INC.

Dr. NAILL. Thank you, Mr. Chairman, and thank you for inviting me to testify before you today.

I have one chart I'd like to use with the oral testimony this afternoon.

This chart describes the results of a set of electricity forecasts prepared in the spring of 1985. In this analysis we developed a base case similar to a conventional energy forecast. We also prepared a number of sensitivity tests which aren't shown in the figure, to examine the uncertainty associated with the base case forecast.

And, finally, in order to address the issue of what is a potential for near term conservation beyond the base case, we developed what we call the "least cost" case that projects electricity demand if all cost-effective end use investments in conservation and conversion technologies are made. And this forecast we think illustrates the degree to which demand management programs could reduce demand for electricity beneficially.

The chart summarizes the base case and the last costs cases and their effect on the need for new generation capacity. In the chart, capacity includes existing plants, new plants under construction and retirements. Demand is represented in the chart by peak demand, and it includes a 20 percent reserve margin. Therefore, when the demand line is below the capacity, the graph indicates a surplus of capacity, and when demand grows above capacity, it indicates a period when new capacity is needed.

Let me now summarize the assumptions and results of the base case projection. In the base case, we assumed that GNP grew at 2.7 percent per year from 1984 to 2005, which includes a faster rate of growth in the near term of 3 percent per year from 1984 to 1995, and 2.3 percent per year from 1995 to 2005. In this forecast, electricity prices are assumed to decline in real terms until 1990 by about 1 percent per year, on average, and then increase from 1990 to 2005.

Prices return to their 1980 peak level by around the year 2000. The net effect of this electricity price forecast is to encourage electricity demand growth in the near term.

Also in the base case, you can see that demand for central station power grows in the chart at 2.4 percent per year from 1984 to the year 2005 and the near term growth rate from 1984 to 1995 is 2.6 percent per year.

Conservation and cogeneration are the main reasons why the growth rate is below the rate of growth in GNP. Assuming no additional cogeneration plants and freezing efficiency gains at their 1984 levels, electricity would grow at 3.2 percent per year compared to the 2.4 percent per year projection in the base case.

Therefore, price-induced conservation and cogeneration reduces the demand for electricity roughly by about 15 percent in the year 2005.

The figure shows that with no new capacity additions, completing the plants under construction will add about 100,000 megawatts of new capacity over the next decade. On average, therefore, reserve margins will decline from about 30 percent now to about 20 percent, which is the critical level in the mid-1990's, unless new central station facilities are constructed, if the base is correct. The base case suggests that about 200,000 megawatts of new capacity will be needed by the year 2005.

By varying economic growth, fuel prices and consumer behavior, we obtained a range of 1.8 to 3.1 percent per year in demand by varying the mid-range or base case assumptions. Again, the mid-range forecast is 2.4 percent per year. And this uncertainty implies that new capacity might be needed as soon as 1992 or as late as 2002, and it implies that utilities might need as much as 300,000 megawatts by the year 2005 or as little as 100,000 megawatts by the year 2005, depending on alternative assumptions in the base case.

We then were interested in exploring, given this potential dilemma of a shortage of generation capacity, what the potential was to manage growth on the demand side. We were interested especially in the demand side because we, as a firm, have found through our work with individual utilities that there is essentially a great deal of untapped conservation and cogeneration potential available in this country. To examine this potential, we created what we call the least cost case, to see how much extra cost-effective conservation or cogeneration potential exists beyond the base case. And the chart illustrates the difference between the base case and the least cost case. And this represents cost-effective conservation and cogeneration that customers are not likely to achieve without outside incentives like conservation programs or third-party businesses.

Utilities can manage the growth in demand and still save their customers money if this potential is realized. In this forecast, demand could be reduced to about 1.6 percent per year growth over the 1984 to 2005 period if all customers took advantage of least cost opportunities. This represents 120,000 megawatts of untapped new resources, 60 percent of which are in the residential sector. The rest are in the commercial and the industrial sectors.

In this least cost forecast, cogeneration increases from about 25,000 megawatts in the base case to about 45,000 megawatts in the year 2000. All of these new demand side resources represent new business opportunities for utilities or third-party firms.

In conclusion, I believe that the idea of utilities pursuing a least cost strategy makes good business sense. Such a strategy provides the missing goals for what utilities now call demand management. In analyzing the impact of such a strategy on a number of investor-owned utilities, we have found significant untapped resources on the demand side in both the conservation and the cogeneration area.

Further, this strategy gives utilities managers more flexibility in determining how to meet potential new load growth. In periods of surplus, utilities could postpone conservation or cogeneration until it's needed. This strategy also could benefit both ratepayers—by lowering prices over the long term—and shareholders—by increasing earnings through reduced construction costs.

In summary, we'd like to submit that the least cost strategy provides a unique opportunity for utilities to manage the demand for electricity in their service area.

Thank you.

[The prepared statement of Dr. Naill follows:]

U.S. ELECTRICITY MARKETS IN THE 1990'S

testimony prepared for the

COMMITTEE ON ENERGY AND NATURAL RESOURCES

by

Dr. Roger F. Naill
Vice President Energy Planning Services
Applied Energy Services, Inc.
1925 North Lynn Street
Arlington, VA 22209

July 25, 1985

U.S. ELECTRICITY MARKETS IN THE 1990'S

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U.S. ELECTRICITY MARKETS IN THE 1990'S

by

Dr. Roger F. Naill
Vice President, Energy Planning Services
Applied Energy Services, Inc.

Introduction

Applied Energy Services, Inc. (AES) is a consulting and cogeneration services firm located in Arlington, Virginia. As a part of its consulting business, AES prepares forecasts of energy and electricity supply and demand for government and utility clients. This report summarizes the results of forecasts prepared in the Spring of 1985, and their implications for the need for new U.S. electric generation capacity.

Analytical Approach

Applied Energy Services, Inc. (AES) has developed projections of U.S. energy and electricity demand based on an "energy services" approach to energy planning. This approach departs from other methodologies by considering energy as a means of providing the services — mobility, comfort, steam or machine drive, for example — associated with healthy economic growth. Instead of the traditional focus on the energy products used (such as electricity, gas or coal), this analysis focuses on the services provided by the use of energy. For example, people do not necessarily want gas or electricity in their homes; they want comfort and convenience. Industries do not really care about using natural gas or coal; they need steam or shaft power to produce their output. The useful energy — the steam, machine drive, heat, or cool air delivered to end-use customers is called energy services.

The concept of the demand for energy services has been embodied in a computer model used to project the long-term behavior of U.S. energy supply and demand. This model projects the demand for energy services in the residential, commercial, industrial and transportation sectors of the U.S. economy — for example, heating, cooling and electric-based services in buildings or steam, process heat and other services in industry — over the next 20 years as a function of economic and population growth. The cost of meeting these energy service demands from alternative conservation and energy conversion technology combinations — including capital, nonfuel operating and maintenance, and fuel costs — is also estimated based on projected fuel prices, technology characteristics, and operating conditions. Conservation and energy conversion technologies then compete for a share of each energy service market, based on these energy service costs.

This representation of energy demand is embodied in the demand sector of the FOSSIL2 model, an integrated model of U.S. energy supply and demand (see Figure 1)[1/]. On the supply side, the energy production sectors of the model are designed to represent U.S. production of each of the major fuels--oil, gas, coal and electricity. The model represents the generation and allocation of investment funds among the production alternatives listed in Figure 1 for each fuel type. The production sectors capture key dynamic mechanisms that control the long-term behavior of energy supply such as resource depletion, delays in constructing new facilities (especially important for electric utilities), the costs of environmental compliance, startup delays in developing new sources such as synthetic fuels from coal, or potential constraints to production. Energy prices are determined endogenously in ~~the~~ model, and "feed back" to affect both the supply and demand for energy over time.

Base Case Projection

Using this approach to modeling the behavior of the U.S. energy system, AES has prepared projections of U.S. energy and electricity demand from 1985 to 2005. The Base Case projection serves as a reference point for judging the likely behavior of demand, for it embodies midrange assumptions about economic growth, energy prices, technology costs and performance, and consumer behavior.

Table 1 shows the macroeconomic assumptions included in the Base Case. U.S. Gross National Product is assumed to grow at an average of 2.7 percent per year from 1984 to 2005, slightly lower than the 3.0 percent per year average growth rate for the historical period from 1970 to 1984. Key indicators of growth in the buildings, industry, and transportation sectors are also shown in Table 1. Those activities tied to population growth — for example, housing units and passenger vehicles — are expected to grow more slowly in the future (1.1 and 1.2 percent per year, respectively, compared to 2.0 and 2.2 percent per year over history). However, industrial production and commercial floor space are expected to grow almost at the same rates as occurred historically, as the economy recovers and expands over the next two decades.

Figure 2 shows the behavior of U.S. energy prices in the Base Case projection. Crude oil prices are projected to decline gradually until 1990, and then increase to about 40 dollars per barrel by the year 2000 (all prices are in 1984 dollars). Wellhead natural gas prices remain low (in the $2 to 3/MMBtu range) until 1990, due to slack market conditions. Over the longer term, natural gas prices are projected to increase as production of less expensive conventional sources declines. Coal prices remain relatively stable compared to other fuels, increasing from an average of $1.30/MMBtu in 1984 to about $1.90/MMBtu in 2005. Average U.S. electricity prices are expected to decrease in real terms until 1990 due to declining oil and gas prices, and due to a reduction in plant construction expenditures added to the rate base. After 1990, however, electricity prices are expected to begin to rise again as fuel prices rise, and as construction of new plants resumes. In general Figure 2 shows that energy prices are expected to remain low due to continued slack energy market conditions for another five years, and then continue their long-term upward trend.

[1/] For a description of the FOSSIL2 model, see U.S. Department of Energy, FOSSIL2 Energy Policy Model Documentation, DOE/PE/70143-02, October 1980.

FIGURE 1

BASIC STRUCTURE OF THE FOSSIL2 MODEL

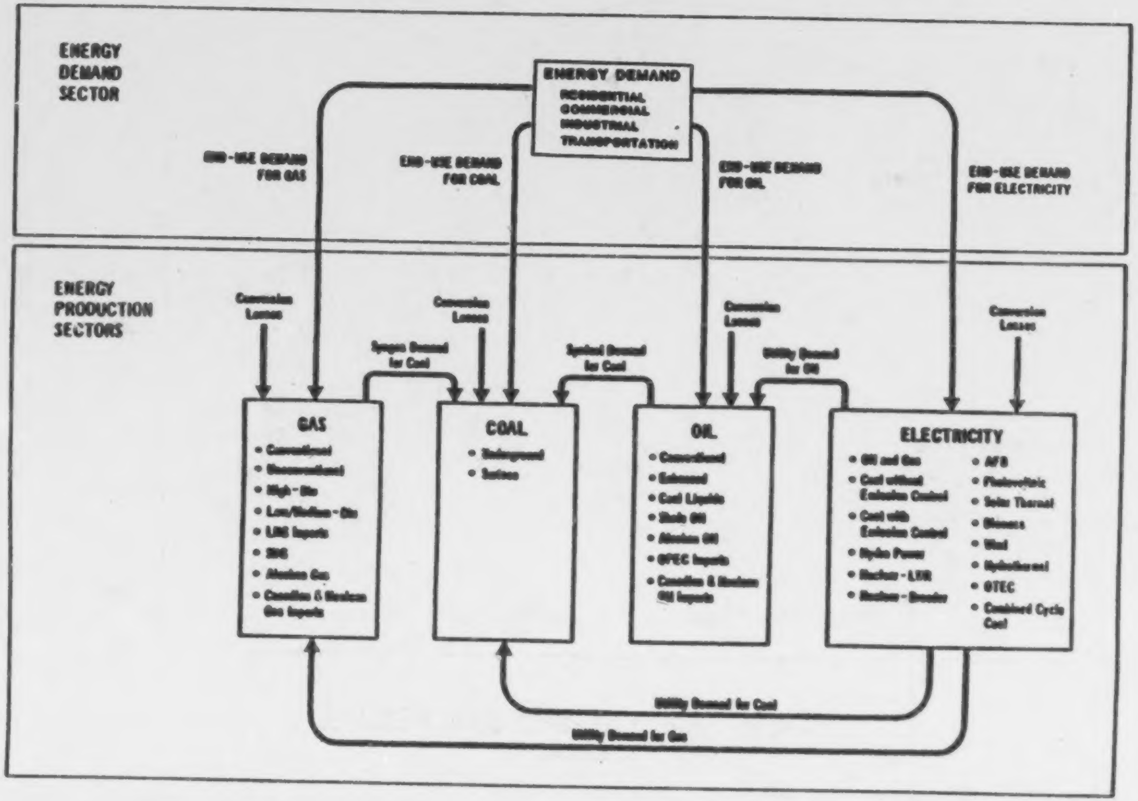

ENERGY DEMAND SECTOR
ENERGY DEMAND
RESIDENTIAL
COMMERCIAL
INDUSTRIAL
TRANSPORTATION
END-USE DEMAND FOR GAS
END-USE DEMAND FOR COAL
END-USE DEMAND FOR OIL
END-USE DEMAND FOR ELECTRICITY
ENERGY PRODUCTION SECTORS
Conversion Losses
Conversion Losses
Conversion Losses
Conversion Losses
Syngas Demand for Coal
Synfuel Demand for Coal
Utility Demand for Oil
GAS
• Conventional
• Unconventional
• High-Btu
• Low/Medium-Btu
• LNG Imports
• SNG
• Alaskan Gas
• Canadian & Mexican Gas Imports
COAL
• Underground
• Surface
OIL
• Conventional
• Enhanced
• Coal Liquids
• Shale Oil
• Alaskan Oil
• OPEC Imports
• Canadian & Mexican Oil Imports
ELECTRICITY
• Oil and Gas
• Coal without Emission Control
• Coal with Emission Control
• Hydro Power
• Nuclear - LWR
• Nuclear - Breeder
• AFB
• Photovoltaic
• Solar Thermal
• Biomass
• Wind
• Hydrothermal
• OTEC
• Combined Cycle Coal
Utility Demand for Coal
Utility Demand for Gas

FIGURE 2
BASE CASE U.S. ENERGY PRICES

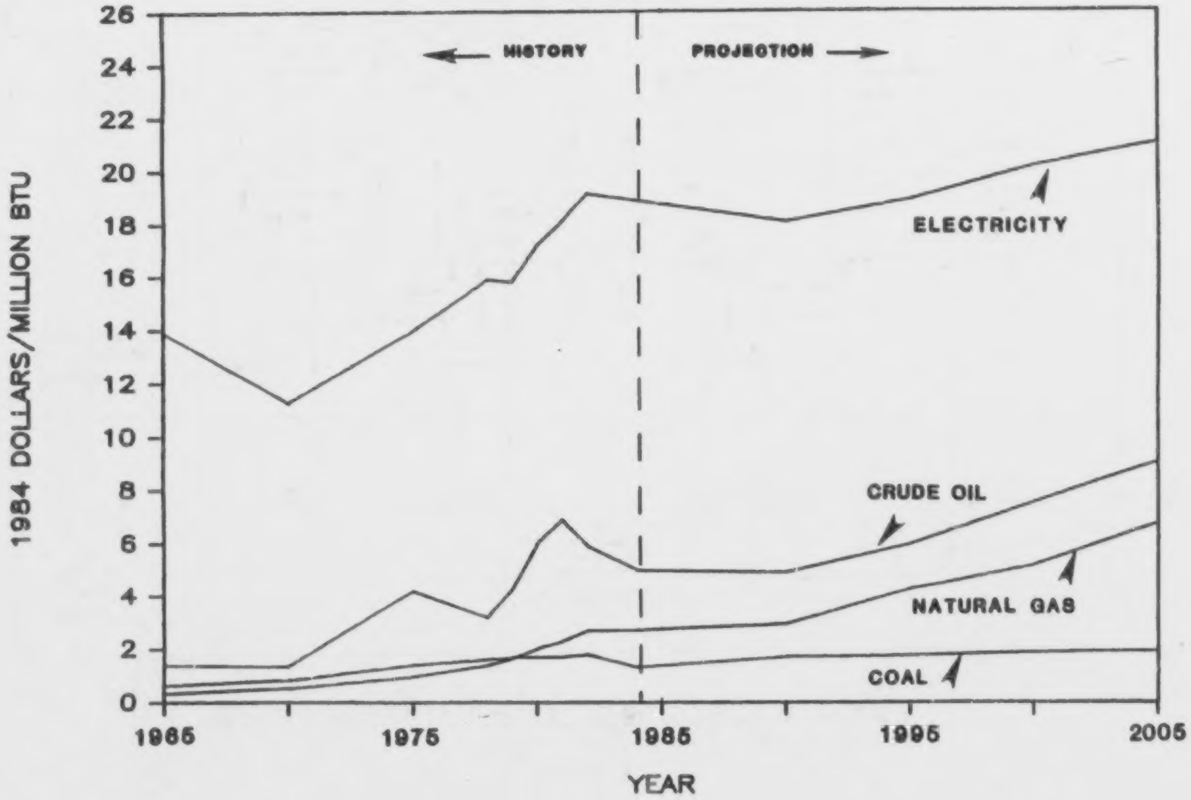


TABLE 1

BASE CASE MACROECONOMIC ASSUMPTIONS

SECTOR	GROWTH INDEX	1970-1984 GROWTH RATE (%/YEAR)	1984-2005 GROWTH RATE (%/YEAR)
U.S. ECONOMY	GNP	3.0	2.7
BUILDINGS	Residential Housing Units	2.0	1.1
	Commercial Floor Space	2.5	2.4
INDUSTRY	Industrial Production	3.1	3.4
TRANSPORTATION	Passenger Vehicles	2.2	1.2

Figure 3 shows the behavior of end-use energy consumption in the Base Case. Total end-use consumption is projected to grow at about 1 percent per year from 1984 to 2005, well below the GNP growth rate of 2.7 percent per year. Electricity is expected to increase its market share from 13 percent of all end-use consumption in 1984 to 18 percent by the year 2005, reflecting primarily the more rapid growth in the use of electric energy services (for example, motors or appliances), compared to other non-electric energy services.

Table 2 show the growth in electric consumption by end-use sector and service category. Total end-use demand is projected to grow at about 2.6 percent per year in the Base Case. In this forecast, residential electricity demand grows at 2.1 percent per year, commercial demand at 1.9 percent per year, and industry at 3.2 percent per year. Table 2 also summarizes the projected amount of cogeneration in the Base Case. cogenerated power is projected to increase from about 13,000 Megawatts in 1984 to 23,000 Megawatts in 1995 and 25,000 Megawatts in 2005. This projection is conservative, for it assumes a continuation of the historical barriers to investments in cogenerated power that cause the hurdle rate for cogeneration investments to be higher than the average industry rate of return (15 percent real after-tax hurdle rate was assumed for cogeneration investments in the Base Case). Yet even with these barriers, cogeneration capacity is expected to double in the Base Case projection. The growth in cogeneration and other dispensed electricity sources (photovoltaics, wind, industrial hydropower) reduce the growth in the demand for centrally-generated electricity by about 0.2 percent per year (from 2.6 to 2.4 percent per year from 1984 to 2005).

Figure 4 shows the behavior of electricity demand and conservation in the Base Case. To illustrate the need for constructing central station plants, the electricity demand shown in the Figure is calculated by excluding power from decentralized plants (cogeneration or small power production). In this accounting, therefore, cogeneration decreases the growth in demand for centrally-generated power. In the Base Case, electricity demand is projected to grow at 2.4 percent per year from 1984 to 2005, about 90 percent of the rate of growth of

FIGURE 3

END-USE CONSUMPTION IN THE BASE CASE

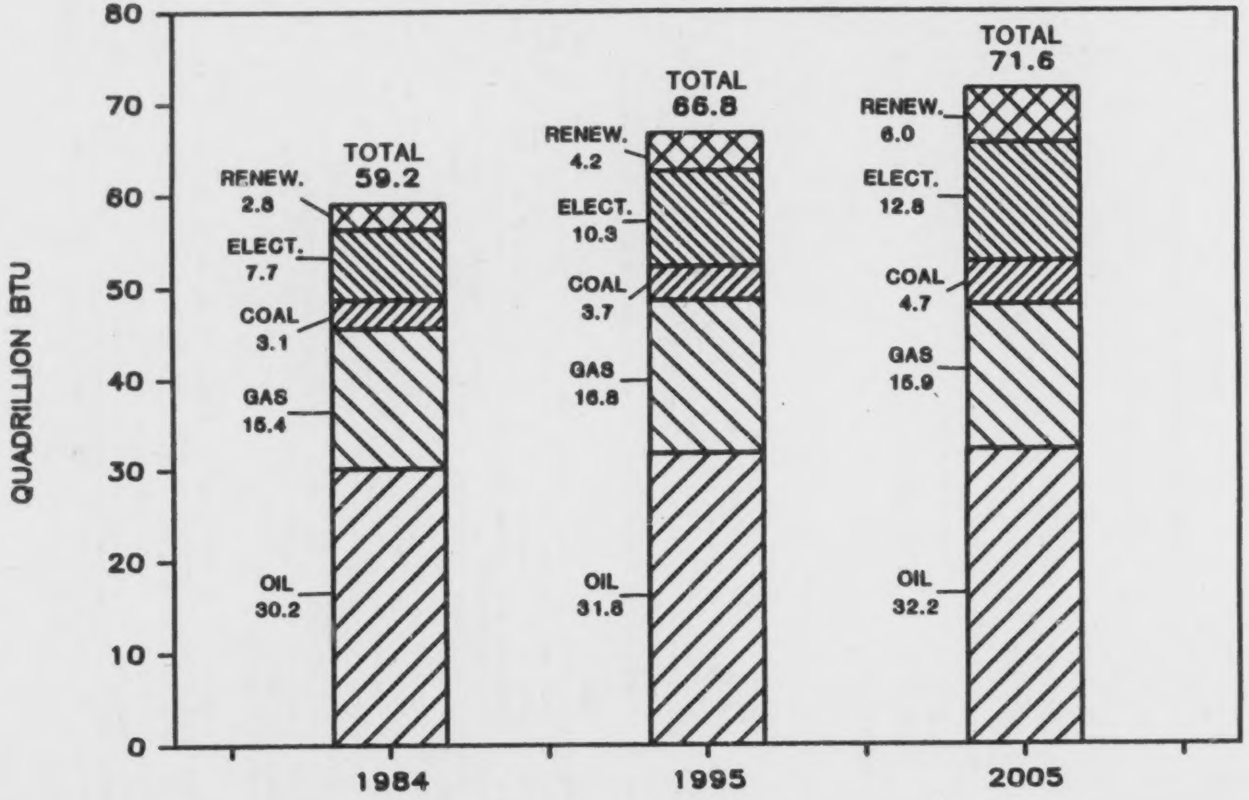


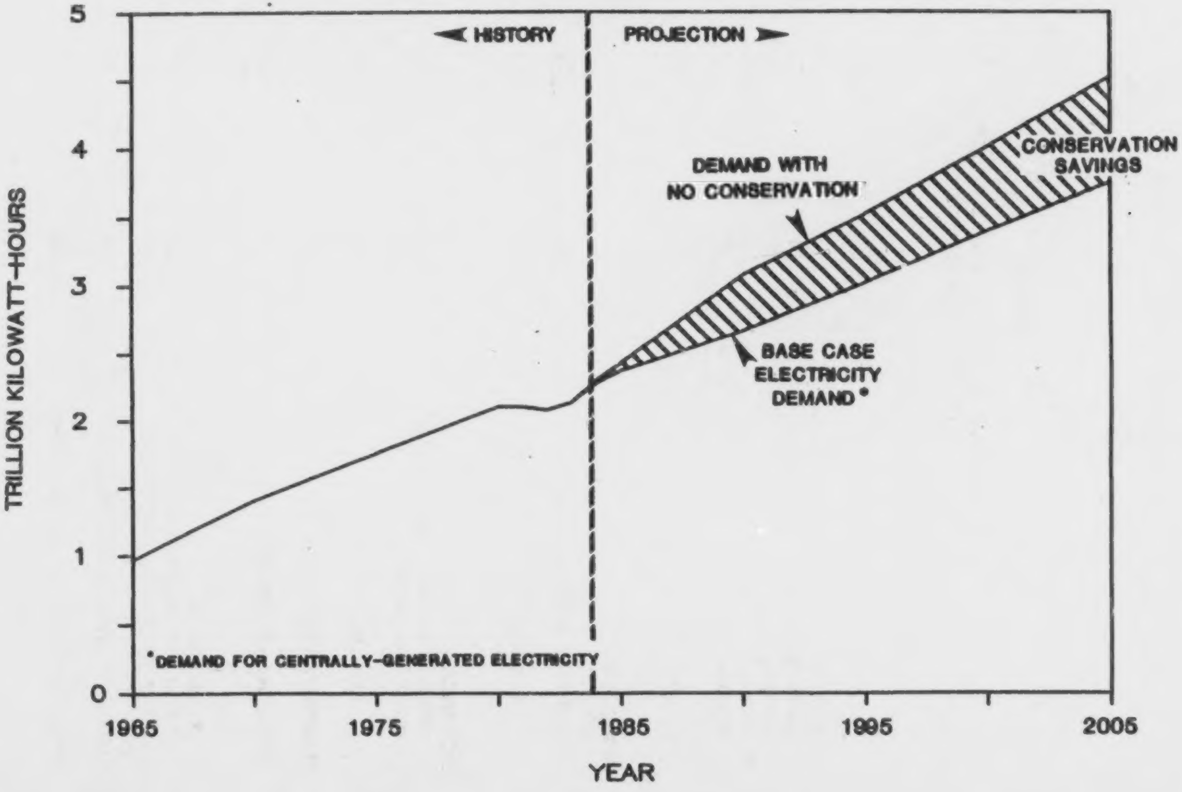
TABLE 2

ELECTRICITY USE BY SERVICE CATEGORY
(trillion kilowatt-hours)

	1984	1995	2005
RESIDENTIAL			
space heating	.14	.21	.30
cooling	.18	.25	.28
thermal	.14	.18	.21
appliances	.30	.33	.38
subtotal	.76	.98	1.18
COMMERCIAL			
HVAC	.25	.27	.33
Lighting & Appliances	.43	.56	.68
subtotal	.68	.83	1.01
INDUSTRIAL			
machine drive & electrolytic	.78	1.24	1.65
other head & misc.	.13	.15	.17
subtotal	.92	1.39	1.82
TRANSPORTATION	.01	.01	.01
TOTAL END-USE DEMAND	2.35	3.20	4.02
cogeneration	.07	.13	.14
(thousand Megawatts)	(13)	(23)	(25)
other dispersed electricity	.01	.01	.09
MINUS: DISPERSED ELECTRICITY	.08	.14	.23
TOTAL CENTRALLY-GENERATED DEMAND	2.28	3.05	3.79

FIGURE 4

ELECTRICITY DEMAND AND CONSERVATION IN THE BASE CASE



GNP (2.7 percent per year). If no efficiency improvements in the use of electric energy were to be made beyond 1984, electricity demand would grow at 3.2 percent per year, the same rate of growth as the growth in electric energy services. The difference between potential electricity demand with no efficiency improvements and actual or projected demand is a measure of conservation. In the Base Case, conservation is expected to reduce electricity demand by 15 percent in 2005. These savings occur primarily as old electricity-using equipment is replaced with new, more efficient equipment. Referring to Figure 2, the projected conservation is due primarily to the electricity price increases of the 1970's (not the 1980's), which causes new equipment to be built at higher efficiency levels than existing equipment.

Figure 5 summarizes the implications of the Base Case projection on the need for new central-station generating capacity in the United States. Current (1984) system generating capacity is about 625,000 Megawatts for the U.S. as a whole, and increasing. Between 1982 and 1984 about 40,000 Megawatts of new capacity were added to the U.S. electric system. These new plants were primarily coal or nuclear units started in the early 1970's when demand was growing rapidly (and was expected to continue to grow). Because demand growth has slowed considerably, most utilities now have large amounts of surplus capacity (the average utility's reserve margin was over 30 percent in 1984, according to NERC data) [2/], and if the plants currently under construction are completed as scheduled, capacity will increase another 86,000 Megawatts over the next ten years. So even with no new construction plans, total U.S. generation capacity should exceed 700,000 Megawatts by the turn of the century, just by completing plants under construction.

Figure 5 also shows the demand for central-station plants, measured by the capacity needed to meet projected demand (including a 20 percent reserve margin). Because of load management, the average system load factor is expected to improve over this period. Peak demand should therefore grow more slowly than sales accounting for perhaps 0.3 percent per year difference between sales and load growth. To meet peak demand reliably (with low probability of brownouts or system failures), capacity should be at least 20 percent above peak demand, on average (while utilities are loath to define a measure of their system's reliability so simply, this target reserve margin does capture most utilities' system planning goals). Figure 4 indicates that with the Base Case forecast of electricity demand of 2.4 percent per year, about 200,000 Megawatts of new central-station capacity (in addition to that already under construction) will be needed by the year 2005. With no new orders, reserve margins might be reduced below 20 percent by the mid-1990's. Assuming that new orders are likely to be for long lead-time coal plants, utilities would have to begin to place firm capacity orders now (the mid-1980's) in order to avoid shortages in the late 1990's, according to this forecast.

Uncertainty

As shown by the events of the last decade, forecasting electricity demand has become a risky business. Most electric utilities overforecasted electricity

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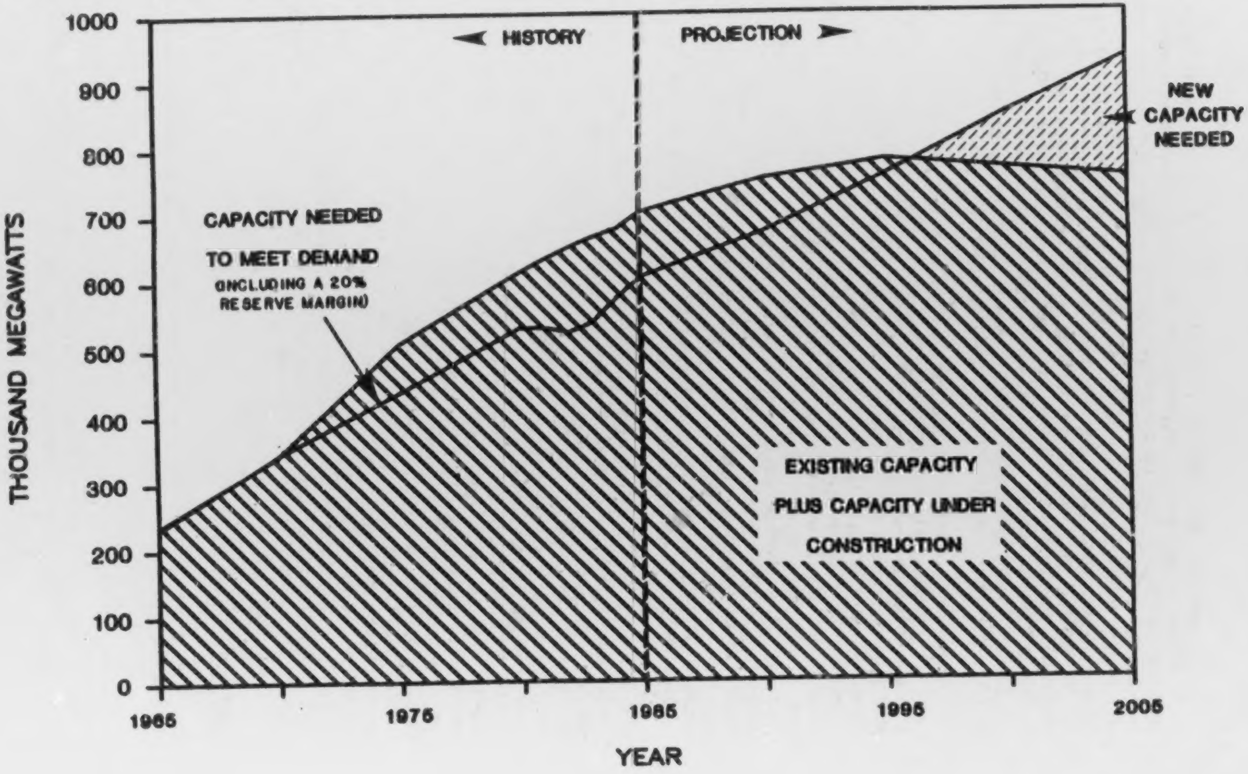
[2/] North American Electric Reliability Council, Electric Power Supply and Demand 1984-1993, Research Park, Terhune Road, Princeton, N.J., 1984.

FIGURE 5

PROJECTED NEED FOR NEW GENERATION CAPACITY IN THE BASE CASE



demand in the 1970's. In the past, utilities often used simple trend methods to forecast future demand, where electricity demand for the next 10 years was an extrapolation of the previous 10 years. Since electricity demand grew steadily at about 7 percent per year up until 1973, most forecasters assumed this trend would continue, and ordered new plants accordingly. But electricity demand growth has averaged only 2.6 percent per year since 1973, due primarily (upon hindsight) to the effects of lower-than-expected economic growth and greater-than-expected conservation.

Most utilities now recognize that they must account for factors such as economic growth and prices when forecasting future electricity demand. Yet taking these factors into account doesn't avoid the uncertainty associated with forecasting. Any assumptions about future economic conditions or prices are uncertain, and result in an uncertain forecast of electricity demand.

To measure the potential uncertainty associated with forecasting electricity, Table 3 show the behavior of electricity demand under alternative assumptions about key input parameters. Low and high assumptions were made about future economic growth (a range of 2.1 to 3.2 percent/year economic growth from 1984 to 2005 was assumed), oil prices (a range of 34 to 72 1984 dollars per barrel in 2005), and consumer behavior about energy conservation (resulting in plus or minus 10 percent difference in end-use efficiency improvements by the year 2005). Using these assumptions, electricity demand could vary from a low of 1.8 percent per year to a high of 3.1 percent per year over the next two decades (see Table 3). With the low growth rate, new construction would likely not be needed until after the year 2000 (see Figure 6). If electricity demand were to grow at the high end of the range (3.1 percent per year), new capacity might be needed as soon as 1992.

Managing Growth

If these forecasts are correct, many utilities should begin now (or within the next few years) to order new generation capacity for the 1990's. Yet most utilities are reluctant to make such a commitment. Electricity managers are wary of forecasts of high demand growth, for demand has by all accounts grown well below expectations over the past decade. Though improving, investor-owned utilities' financial positions remain uncertain. Most utility managers would prefer not to have to finance any new capital expansion, given today's financial conditions. The cost of that capital is so high that it risks the financial health of the company.

One alternative to this dilemma is for utilities to begin to manage the growth in electricity demand just as they manage their generation resources. AES's approach to managing electricity demand growth stems from a concept we call a "least-cost" strategy. The idea is for utilities to stop thinking of themselves solely as deliverers of electricity, but instead as marketers of energy services: the heat light, or power needed to operate the buildings and industries in their service area. Their strategic objective would be to deliver energy services at the lowest possible cost to their customers; hence, it is called a least-cost strategy. What is different about this strategy from utilities' current way of doing business is that it leads them to consider

TABLE 3

Projected Uncertainty in the Electricity Demand Forecasts

Key Assumptions

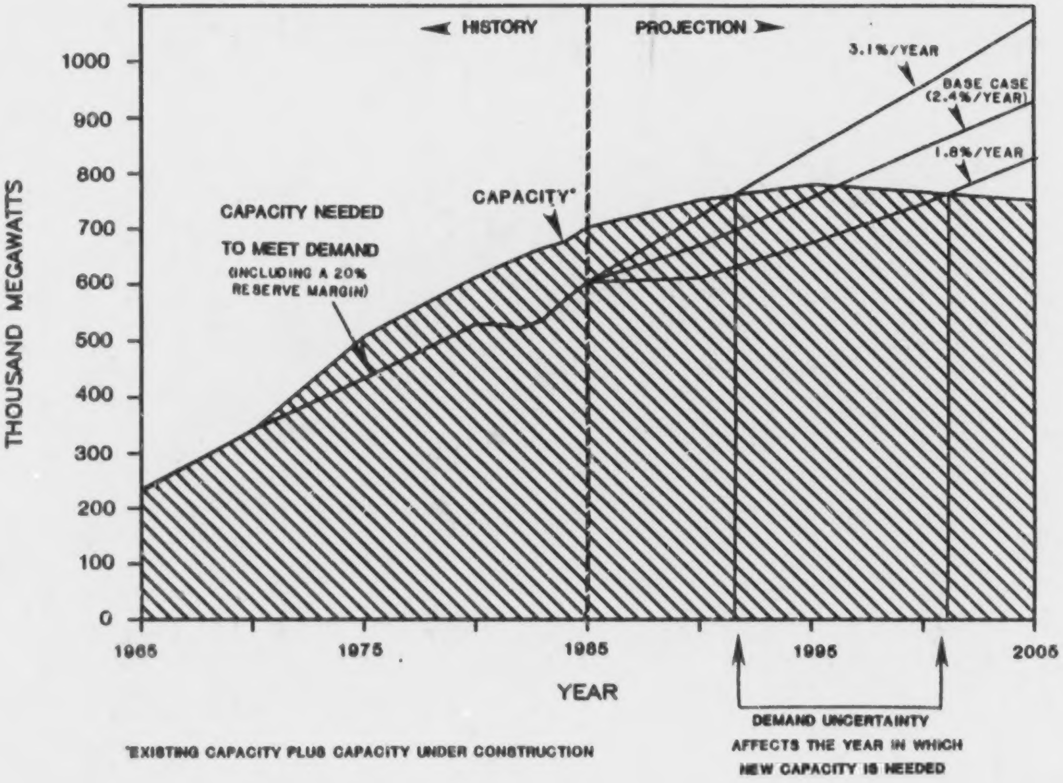
	Low	Base	High
Economic Growth (1984-2005 GNP growth)	2.1	2.7	3.2
Oil Prices (2005 Crude Oil Price)	34	52	72
Consumer Behavior (average efficiency improvement from Base Case in 2005)	+10%	--	-10%

Sensitivity of Electricity Demand to Uncertainty
(percent/year, 1984-2005)

	Low	Base	High
Economic Growth	1.8	2.4	3.0
Oil Prices	2.5	2.4	2.5
Consumer Behavior	1.8	2.4	3.1

FIGURE 6

EFFECT OF UNCERTAINTY ON THE NEED FOR NEW CAPACITY



*EXISTING CAPACITY PLUS CAPACITY UNDER CONSTRUCTION conservation options (or end-use technologies that conserve electricity) on an equal basis with constructing new generation facilities in their resource planning. The growth in electric energy services in their service area can be met by either saving or generating electricity. Marketing energy services rather than electricity therefore opens up a whole new set of options in utilities' strategic plans.

By examining electricity's role from the perspective of electricity as one of many options to meet customer demand for energy services, one discovers that a surprising amount of competition is going on in what is traditionally thought of as a monopoly industry. Most electric customers in fact have many alternative to central electric generation: for example, insulation, heat pumps, efficient light bulbs, and cogeneration all are playing a major role in determining electricity's future market share. This competition with central electric generation can be either a threat or an opportunity to the utility. For electric utilities in the 1980's, competition can be a threat to future load growth, but at the same time an opportunity to better control that load growth and create new business activities. Our experience suggests that those utilities that take advantage of the opportunities presented by pursuing a least-cost strategy (rather than reacting defensively to the threat to their load growth) will be the success story of the next few decades.

To help utility planners sort out the implications of following a least cost strategy, we created a "Least Cost" projection with our energy model. The Least Cost case shows the behavior of energy and electricity demand if all cost-effective end-use investments are realized. We implemented the Least Cost case by lowering the consumer discount rate, or hurdle rate for making end-use investments, to a theoretical minimum value of 5 percent per year (real after tax return assumed in the model). This value represents the historical average rate of return of all industry investments over the past few decades, and thus might represent a reasonable measure of cost-effectiveness for future conservation investments. While the Least Cost case is theoretical, it is useful because it indicates the maximum cost-effective conservation potential achievable.

The results of this least cost analysis suggests that demand for central-station power plants might be reduced by an additional 120,000 Megawatts by 2005, and save the customers money at the same time. Table 4 shows where those potential savings might be, by end-use sector and by technology. By far the largest share of potential reductions might be found in the residential sector -- approximately 70,000 of the total 120,000 Megawatts. Residential shell improvements (for example, insulation, reduced infiltration, or clock thermostats) represent one-third of the total savings, and are the largest single category. Also of potential importance are added savings from residential lighting and appliances (30,000 Mw), commercial lighting (13,000 Mw), and industrial cogeneration (19,000 Mw).

Figure 7 shows that these savings could reduce electricity demand in the year 2005 by about 15 percent, compared to the Base Case projection. U.S. electricity demand could grow at about 1.6 percent per year if policies were implemented to achieve the full Least Cost potential, compared to 2.4 percent per year in the Base Case. Managing demand according to a least cost strategy could postpone the need for new central-station power plants by almost 10 years. In fact, many utilities are implementing such a strategy where conservation programs and cogeneration are used as the "marginal" resource to meet new capacity requirements in utility resource plans.

FIGURE 7

THE EFFECT OF A LEAST-COST STRATEGY ON THE NEED FOR NEW GENERATION CAPACITY

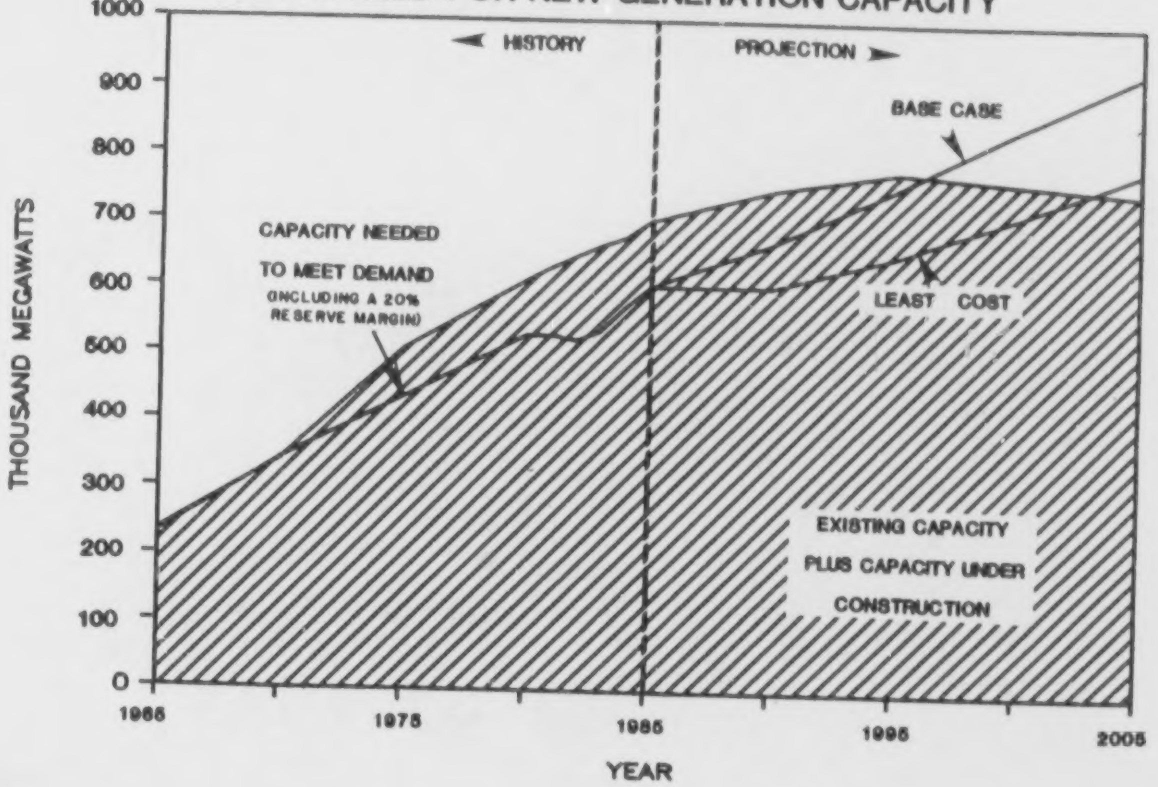


TABLE 4

WHERE ARE THE POTENTIAL SAVINGS?

		YEAR 2005 LOAD REDUCTION*	
SECTOR	CONSERVATION MEASURE	THOUSAND MEGAWATTS	PERCENT
RESIDENTIAL	shell retrofits + HVAC	40	5.3%
	efficient lighting & appliances	32	4.2
COMMERCIAL	shell retrofits + HVAC	3	0.4
	lighting	18	2.4
INDUSTRIAL	cogeneration	19	2.5
	motors & miscellaneous	8	1.0
	TOTAL	120	15.9%

*potential cost-effective reductions from Base Case forecast.

A least-cost strategy could make good business sense for electric utilities. The overall goal of such a strategy is consistent with the utilities' mandate - providing energy services to customers at the lowest possible cost. The first step to implementing such a strategy is a shift in focus from selling electricity to selling energy services. Utilities might redefine their role to one of providing customers with energy services - heating, cooling, lighting, or machine drive - at the lowest possible cost, not just electricity. This cost would take into account not only the traditional costs of generating, transmitting , and distributing electricity, but also the end-use equipment costs associated with delivering electric energy services. By operating as energy services companies, utilities would have access to new demand-side tools to manage the long-term growth in their load, improve their competitiveness, and thus to minimize the cost of energy services in their service area.

From the utilities' perspective, a least-cost approach to planning suggest that if additional resources are needed to meet future load growth, utilities might examine the untapped resources in their end-use sectors as alternatives to constructing traditional central generation facilities. By embarking on conservation programs or contracting for cogeneration electricity, for example, utilities can purchase significant quantities of resources that likely will not occur from normal market forces alone. These Megawatts are often cheaper than building traditional generation facilities, resulting in less need for financing of new debt and equity. As a result, earnings per share would be less diluted, and the strain of financing large amounts of high-cost debt is decreased. A least-cost strategy might also lower electric rates to customers over the long term, as average fixed costs increase more slowly than otherwise. For example, for one West Coast utility, our calculations suggest that earnings per share could be increased 4 per cent and rates could be lowered up to 13 per cent by the year 2000 if a least-cost strategy were successfully implemented.

For utilities with little demand for additional capacity, managing load growth could also benefit both ratepayers (by lowering the cost of energy services over the long term) and shareholders (by increasing earnings per share). Lower demand could allow early retirement of expensive oil- or gas-fired generation capacity. Further, the detailed identification of end-use markets might focus opportunities to increase load where capacity is significantly underutilized. Heat pumps to replace gas furnaces and promotional rates to retain industrial demand are but two examples of this approach.

Many investor-owned utilities already have some impressive programs under way that exemplify the beginnings of a least-cost, energy services approach. San Diego Gas and Electric Company had a subsidiary (recently spun off) that makes electricity and steam through cogeneration and sells the steam at a discount to customers, primarily the U.S. Navy. The Pacific Gas and Electric Company provides zero-interest loans for their customers to improve the efficiency of their homes and hence lower the cost of heating and cooling. Northeast Utilities has an extensive program of residential conservation and load management. The Southern California Edison Company, Pacific Power and Light Company, Southern California Gas Company, General Public Utilities, Public Service Company of New Mexico, Arkansas Power and Light Company, Florida Power and Light Company, Texas Utilities, and many others have programs of various kinds that are testing the energy services approach. In fact, a report by the

Investor Responsibility Research Center in Washington suggested that a "virtual stampede" now exists to make conservation and load management - key elements of an energy service approach - part of their overall operations. About 86 of 120 utilities surveyed have adopted formal conservation programs [3].

As we have indicated, the benefits from pursuing a least-cost strategy will vary substantially from utility to utility. Utilities with a great deal of excess generating capacity have little need for added conservation or cogeneration now, even though these options might be cost effective from the consumer's perspective. In those cases, a marketing strategy is needed to guide the utility through the period of surplus. Here, the timing of its demand management programs is important. In the near term, the utility might concentrate its efforts on increasing its market share where electricity is the least-cost choice, or by offering electricity sales from excess capacity at bargain rates. Over the longer term, when the surplus is gone, the utility might accelerate its conservation efforts.

Any strategic plan, including the least-cost strategy proposed here, contains operational risk: the risk that in actual operations, the company's planning assumptions were wrong. For example, the risk of higher or lower fuel prices than planned makes generation planning uncertain at best. Implementing a least-cost strategy would shift some of the operational risk from generation to demand. For example, while the demand reductions shown in the least-cost projections may be a good planning goal, an operational risk is that these demand reductions will not be achieved - and the utility would therefore need more capacity than planned. One way to hedge against demand risk is to shorten the lead time needed to bring on new generation facilities. For example, the Northwest Power Planning Council has proposed the purchase of capacity "options" (where the time-consuming but low-cost tasks of siting and permitting are initiated), while monitoring demand to see if new capacity is needed [4].

This analysis suggests that the emerging competition for electricity market share is real: competition from other fuels, from conservation, and from unregulated power generation (small power generation and cogeneration) all will help to lower customers' energy service costs in the future. Over the next few decades, utilities have a unique opportunity to manage the demand for electricity in their service area by implementing timely conservation and cogeneration programs. A demand management strategy based on least-cost principles offers new opportunities for utility managers to meet the growing competition for energy markets in the 1980's.

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[3] Douglas Cogan and Susan Williams, Generating Energy Alternatives: Conservation, Load Management, Renewable Energy and America's Electric Utilities, Investor Responsibility Research Center, 1983.

[4] Northwest Power Planning Council, Northwest Conservation and Electric Power Plan, April 1983.

Senator **Evans**. Thank you.

Thank you all for interesting and consistent views of the future. As nearly as I can detect, we're anywhere from zero to 5 percent per year in terms of growth—and I haven't calculated what that turns out to in the width of a band of expectations by the year 2000—but it's probably more central station plants than I can count.

Let me try to get at some questions that, hopefully, will narrow some of that a bit. It seemed to me, Mr. Siegel and Mr. Sillin, you differed quite considerably from Dr. Williams and almost each one of you has attempted to relate the potential growth of electric demand as a ratio of the gross national product. And we get some widely differing viewpoints as to just what's going to happen. And as I look at the charts you've used, it seems to me that wherever you come out—I wouldn't suggest it's where you want to come out necessarily—but wherever you come out depends on where you start.

The one chart—Mr. Gent, your chart on figure 14 shows a sharply larger rate of growth for electricity consumption than the growth in real GNP during a period starting in 1960. However, I think it's probably accurate to say that virtually all of that growth, or difference in growth, occurred prior to the oil shock of 1973, and none since.

The expectations of Mr. Siegel and Mr. Sillin, it seems to me are based on relating the past ratios, the past makeup of our economy with the future, and Dr. Williams suggests that it's going to be quite different; that we will have a much less energy intensive future, even in spite of the same rates of gross national product growth.

In a return to the testimony this morning of Secretary Boggs and the Department of Energy, at least in his statement, he had a chart that showed the ratio of electric growth to GNP growth, 36-month rolling average. That, it seemed to me, showed some—of course, it bounces up and down and he leaves out a period of 1 year, saying that from December 1982 through October 1983, negative values and values near zero make these numbers unrepresentative.

Be that as it may, there seems to be some fairly interesting and well sustained trends in those figures that the Department of Energy has set forth. From about 1979 when this 36-month rolling average bottomed out at least at that period, to about 1981, there was an uptake, going from about 0.6 clear up to 1.0 in terms of electric growth to GNP growth.

But since that time, you take any kind of a trend line and from 1981 clear through the first months of 1985, according to the Department of Energy, has been a steady downward trend from 1 down to something, I would say, close to 0.6 in that 36-month rolling average.

I guess I'd like to get at that. Is DOE wrong? You know, who's right and who's wrong?

First, Mr. Sillin and Dr. Siegel, in your view will there be any change from historic patterns in the—I guess the unit energy, electric energy intensity of American industry?

Dr. **Siegel**. I think we can all agree that that ratio has not been static. It was very clearly, as Secretary Boggs pointed out, averaging in the 2-to-2 ratio up until 1973. And it declined, according to our data, and we use a 5-year rolling average. We think it smooths out downturns in the economy.

According to our data, it bottomed out in 1983 at 0.8, and in 1984 had turned up to 0.83. Maybe you can't distinguish between three one-hundredths of a point, but we think the trend line has stopped dropping.

Now, point one, it is not static.

Senator **Evans**. You say in 1984 it was what? It bottomed out, you say, in 1984?

Dr. **Siegel**. 1983.

Senator **Evans**. In 1983.

Dr. **Siegel**. At 0.8 relative—if you look at the electric output in 1984 versus 1979, that's our 5-year rolling average, the electric was 0.8 of GNP.

Senator **Evans**. It would seem to me with a 5-year rolling average, you're going to run out pretty quick of those high figures of 1980 and 1981. And in looking ahead, unless there are some sharp increases in that ratio, a 5-year rolling average would continue to decline, not go up, because you're going to run out of those first years that were the highest.

Dr. **Siegel**. Well, the point I wanted to make——

Senator **Evans**. Well, would you care to comment on that particular point?

Dr. **Siegel**. Our basic hypothesis is that the ratio is going to turn up for the very same reasons that it turned down starting in 1973. We think the downturn beginning in 1973 was the result of three factors: Rapid runup in real price of electricity; two, the rate of the economy fell to half of its pre-1973 growth; 1973 to 1982, it averaged 2.2; the previous 20 years, 4.5 and then real income, real consumer income which had been growing at 3 to 4 percent in the 1970's, fell to a rate of growth of one-half percent over the 1970's.

We think that now, beginning in 1982, real income is rising. We predict higher rates of GNP, and we predict falling real electric prices. And the reason we say the electric content, that ratio is going to turn up, is because price elasticity effects work both ways. When prices start to fall, the relative usage will rise.

Second, the cross price elasticity effects of the much greater runup in oil and gas prices are very long-term effects, take 12 or more years to roll through the system. We're only now beginning to see the impact of those very rapid runup in oil and gas prices which occurred around 1980.

Another point is that the capital investment rates and the rising real income, we think, will strengthen the ratio. If you go back and look at the last 30 years of history, you'll see that that ratio has always turned up during the two—we've had two sustained growth periods. One was the middle 1960's when the Kennedy administration implemented a number of economic policies, including a tax cut; and in the early 1950's, there was a very large sustained rate of economic growth. Both times, the electric content of GNP turned up, and it turned up dramatically.

I might point out, unfortunately we didn't spend as much time on this in our testimony as we should have—since 1979, 1979 through 1984, which is a 5-year period, GNP has grown 10 percent. As Danny Boggs pointed out this morning, there was no growth between 1982 and 1979. All of the growth in GNP relative to 1979 has come in the last 2 years. It is up 10 percent in that 5-year period.

In the same 5-year period, commercial sales of electricity have increased 22 percent, residential sales have increased 14 percent. They are running way ahead of GNP. The sector which has shown no growth—and maybe now I'm beginning to answer your question—is the industrial sector. The electric content of industrial activity has been unchanged. It is not falling, it is not increasing. We think that's favorable comment.

The second thing, though, is the industrial production hasn't changed since 1979. It's almost flat in this country. We think in large measure that's the result of the runup in the U.S. dollar which had gone up close to 60 percent between 1979 and early 1985. It's coming off now. I'm not going to sit here and tell you where it's going, although I would do no worse than most economists have done. But we think that the dollar—we think that with the dollar coming off, that the industrial sector in this country will recover and we see, if that recovery comes, very easily the electric content relative to the GNP will increase.

I can't see how people can say that the ratio is—you know, it's not a static ratio. And one ought to look at what caused it to decline, and are those very same factors now undergoing a reverse. We think they are.

Senator EVANS. There's a sharp differential by industry when you disaggregate the industrial sector in the use per unit of output and the big, big electric users are grouped in relatively few industries.

Do you foresee any of those very energy-intensive industries as being part of our future growth? The multiples are so much—I forget who had that chart. Did you, Dr. Williams? Where is that in your——

Dr. WILLIAMS. That's figure 2, electricity intensity.

Senator EVANS. And to the degree that primary metals represent, if I understand it correctly then, 23 percent of all of the industrial electrical use—chemicals, 22.5; petroleum refining, 4.6; paper, stone, clay, and glass. And then you get down to all other.

Mr. Siegel or Mr. Sillin, where do you think the industrial growth is going to be in the next 10 years? As a percentage of total growth, how much of it is going to occur in primary metals, chemicals?

Mr. SILLIN. I think what we would say is that we think that big industry, if you will, will play a relatively smaller role in the total U.S. economy than it has in the past. I wouldn't quarrel with that statement at all.

But I think the statement that we would tend to disagree with is that big industry is going to go away completely. I would think that while the industry, big industry has been hit hard recently by, for example, the run-up in the dollar which we've talked about—if you look at the capital investment numbers that are coming out, for example, from the Conference Board, they show manufacturers—including some of our traditional industries—making dramatic increases in capital expenditures. That to me is not a sign that big industry is drying up and going away.

In fact, if I look at what, for example, you know the Japanese are moving automobile manufacturing plants into this country; they're generally thought to be pretty sharp characters, and if they see advantages in locating businesss in this country, I think that speaks, in general, well for the future of the industry in this country.

Senator EVANS. Have you done any analysis, however, attempting to disaggregate industrial groups and take any shot at where the growth is going to be?

Mr. SILLIN. Not specifically, but let me make one—let me——

Senator EVANS. Just a moment. It seems to me that it makes a big difference. Certainly our basic industries aren't going to dry up and go away, but if, per unit, primary metals are up in the 25 to 27 compared with all other, big other category, down at 3, that's about a 8 to 1 ratio. We don't have to change very much to change the use of electricity, for example, quite a bit.

Mr. SILLIN. Senator, I'm not an end use expert on electricity. I'm not going to claim that. But let me just point out an example of a region of the country where, for example, big industry is thought really not to exist now, and that's, for example, in New England. New England is thought to be a sort of a service-based economy right now, relatively light industry, high tech. So there you would expect to be a region where you would not get much in the way of electric growth; that is, the energy content there is thought to be down. Yet, the last 3 years have seen remarkable increases in electricity consumption in that region, in the 4 to 5 percent range.

Clearly, that increase in electricity consumption is coming from somewhere. It's obviously coming, I guess, from——

Senator EVANS. Have you attempted to find out where?

Dr. SIEGEL. Commercial and residential.

Mr. SILLIN. Plus industrial in some form. Maybe different industry than it has been in the past, but industry nevertheless.

Dr. SIEGEL. Their big industry went down the tubes in about 1973. They restructured their economy and now they have this very strong growth.

Our forecast is not—you know, you've gone now into the end use. There are two types of ways of predicting electric demand. There's an econometric way where you just—you try to predict the rate of growth of GNP and the electric content of GNP. Or you can go to the end use and look at industries, count industries, count houses, count commercial buildings.

We haven't attempted to do that. On an econometric basis, I could tell you that the electric sales that are now going to the residential and commercial sector—and that's the base that is growing very rapidly—have increased from 54 percent in 1979 to 61 percent in 1984.

So, yes, the industrial component is growing very slowly, if at all now, but the growth is coming from the base that is growing, and that's one point.

Senator EVANS. I've had considerable experience in the last several years before coming here with the Pacific Northwest Power

Council in dealing with both end use and econometric forecasts. Each has its strengths and each has its weaknesses. And, of course, once you start talking about the future, you're into a real morass.

We, frankly, with all of the intensity we worked on it, finally gave up on any hope of reaching a single point forecast. We figured we could come closer to figuring margins than we could the most likely. And I suspect that across this panel, that's probably what we have done. You clearly have tried to identify a time margin. I'm not quite sure who's the lowest. I guess Dr. Beyea may be, in looking at the future.

The real trick, it seems to me, on electric future is to try to—we don't know where we're likely to end up within that band of growing width as the years go on, but try to achieve a mix of responses that will allow you to meet whatever the demand happens to be in a timely fashion as you look toward the future—and I think that's the trick.

I think, Dr. Williams, do you have any comment directly on—well, one further comment on Mr. Sillin and Siegel's approach. In reading sort of the summary of your measure of electric load growth, you talked about a continued movement toward electricity as a share of industrial usage. And I guess there is that potential, but it seems to me that in almost anything, the larger the percentage that you move toward, the more likely you get to a point where future percentage increases will diminish. You saturate the market, and the growth will not continue in a straight line, but tend to slow down.

And then, in addition to that, you talk about the non-linear ratios, but you use the term "appears" to have this relationship. And then that real electricity prices could decline. It seems to me that that—collectively, those three things add up to pretty slim reeds on which to make positive or definitive forecasts for the future, and you depend on continued movement toward electricity over an extended period of time and say that we appear to have a non-linear relationship, and real electric prices could decline. Any one, or all three of those, might not happen. Then what happens to your projections?

Mr. SILLIN. I would make the argument that all three of those seem to be working in our favor as of right now, though.

Senator EVANS. As of right now. But over what period of time? The last couple of years?

Mr. SILLIN. Well, it's only for the last 2½ years that we came out of what we consider to be the stagnant economic condition of the 1970's.

Senator EVANS. Doesn't that argue, if you come out of a stagnant condition, that the first acceleration is larger than you would suspect any sustained direction to be? It's almost like an automobile accelerating from 0 to 34 miles an hour. It's the first few seconds that you get most——

Mr. SILLIN. Not if you've had an extended period of time of what we consider relatively below par economic growth. Again, from 1973 to 1982, the economy grew at a total average annual rate of only about 2 percent which is dramatically, we think, significantly below the economy's ability to grow. So we feel that the rest of the

1980's are going to be catching up period, catching up from getting up to the real potential of where the economy should be.

So the first 2 years are really, we think, only sort of the coming out, if you will, of the economy.

Senator **Evans**. You have an optimistic view of the future and this is totally aside from electrical load growth. Do you have any advice for us on whether significant reduction of deficit is needed, worthwhile, or won't make any difference as far as the economy growth in the future is concerned?

Mr. **Sillin**. I think we would say that it's certainly worthwhile, that the deficit certainly is something that should be worked on, and that it's certainly worthwhile to reduce it.

But I'm not sure—I think we would also argue, though, that there's a number of other positive economic factors working besides the deficit to sustain economic growth. While the deficit is certainly a negative factor, there are a number of others, what we think very positive factors working to sustain economic growth.

Senator **Evans**. Would you care to enumerate two or three of those?

Mr. **Sillin**. Well, I think what we've talked about, the tax effects, the reduction in taxes. I think that certainly has given a boost to the economy and gotten it back sort of to where it should have been in terms of providing savings and investment incentives, giving people incentives to work harder, that kind of thing.

We certainly think that deregulation, the efforts towards deregulation have made the economy significantly more efficient, thus increasing its ability to grow at a faster rate. And certainly we think that—I'm not going to sit here and tell you I'm a monetary policy expert—but we certainly think that the monetary policy is more consistent than it was beginning in the late 1960's through the 1970's.

And I think you can see those things reflected, for example, in the inflation rates that we're now experiencing and in the fall in interest rates that we're now experiencing, the increases in productivity that we've seen over the last 2½ years or so, a number of factors working positively, we think, towards economic growth.

And while the deficit certainly is important, it shouldn't so color everything else that that's the only thing that's seen.

Dr. **Siegel**. John and I part company sometimes on issues, but generally the same. The deficit is important but it's not the sky is going to fall sort of problem that a lot of—I call them partisan economists—make it out to be.

The U.S. deficit was 5 percent of GNP last year. The average for the other six nations going to the Bonn economic summit was nearly 6 percent. And yet they have no economic growth and we do. The bottom line on my view of the U.S economy is that the U.S. economy has the potential to be far more productive today than it did in the mid-1970's because of the tax cuts, because of the direction the energy scene is going, and because of the tremendus slug of capital investment that is occurring. And I think because of that—and here's where I become somewhat of a Fed beater or Federal Reserve Board basher—I think the economy can sustain a higher rate of growth of money without rekindling inflation.

I think the Federal Reserve Board is feeling its way along, erring on the low side. They want to make sure they don't rekindle inflation. I think the slowdown in the economy that we're seeing now—and that I think we are coming out of—is by and large the end product of the Federal Reserve Board's monetary policy for the last 8 months of 1984 when they basically flattened the money supply. It was nearly a zero rate of growth for 8 months there.

The dollar went—interest rates went up. If the supply of a commodity—in this case, money—stops, the cost of it is going to go up. Interest rates went up, the dollar went up 25 percent. The Federal Reserve Board at the end of the year noticed they had maybe overdone it, and they've reversed that, and now they've brought the dollar down 15 percent, brought interest rate down. And I think the economy is starting to respond and could be very strong growth this year and into 1986. And there is no inflation.

I think the economy can be far more productive today.

Senator **Evans**. I guess we got off of our immediate concerns. I suspect we'd be off the rest of the afternoon if we got deeply into that discussion.

Turning to Dr. Williams, in your fourth point you say overbuilding is very costly insurance policy, however, which is no longer necessary because there are cost-effective supply alternatives which can be brought on line quickly, obviating the need to rely on supply technologies with lead times of a decade or more.

Would you care to expand on that to some degree? And I would ask, further, if we're talking about a more open market for electrical supply, does it make sense to more aggressively purchase efficiencies if, in fact, those purchases bring electricity to the utility cheaper than building a central plant?

Dr. **Williams**. Yes; I think that these small capacity additions can be done either from the part of industry or third parties, or on the part of the utilities themselves. And the utility role in pursuing these small scale technologies should not be slighted, I think, in the least. In my written testimony I gave a lot of discussion of cogeneration which I did not deal with in my oral testimony, and I just wanted to point out one additional thing.

This very technology that I indicated as being so important for central station power generation, that is, the steam injected gas turbines, also turn out to be very important for cogeneration. And, in fact, the technology was originally introduced in 1981 for cogeneration applications. And what it does is, it enables gas turbine cogeneration to provide a rate of return on the investment to the cogenerator which is essentially independent of his steam load. And the basic idea is gas turbine technology is interesting technology for cogeneration in baseload applications when you have steady steam loads. But the part load efficiency of gas turbines is so poor that you can't operate them very economically efficiently with variable steam loads.

And so a patent was obtained on the idea of taking the steam that is not needed for process use and to inject it back into the combuster, run it through the turbine, to get out more power at higher efficiency. And what this means is that gas turbines which are incredibly good for cogeneration not only because of the high thermodynamic efficiency, but because of the very low capital cost, as is shown in figure 6 attached to my testimony relative to all the other technologies for cogeneration, but it means all of a sudden that you can use the systems in essentially every scale of operation, all the way down to scales on the order of a megawatt. Instead of restricting gas turbines to the very large scale operations in chemical plants, petroleum refineries, and whatnot, you can operate them in universities, in food processing plants, because whenever the steam load goes down, you don't even have to predict what it is—if you inject that steam back into the turbine, you produce more power at higher efficiency and the economics look very good as long as you have a market for that electricity, either with onsite use or with sale to the utility through some kind of PURPA provision.

That is very important for, as I say, cogenerators. The same technology essentially I think is even more important for central station power generation. That's what I focused on in my testimony here. And it should be interesting to policymakers, I think, why this technology wasn't around 10 years ago—because it's not a new idea. This steam injection idea has been around for 25 years. In fact, many of the gas turbine community are irate that this fellow got a patent on this particular technology, but it's a very important one from the point of view of economics, from the point of view of environment, from the point of view of fuel flexibility, very important strategy with regard to synfuels, and this technology—if you start these things off on natural gas, when the price goes too high then you can switch at a later date to coal—gas based on coal. But the efficiency is so high with these, for central station power generation—as I say, it's 50 percent—that that date can be forestalled for a very long time.

These things can be brought on line in a year's time, and so essentially obviates the need to rely on long lead time powerplants for this very uncertain environment as to what the future demand growth is going to be.

Senator **Evans**. We passed a Fuel Use Act some years ago during the period of gas and oil shortages, to move away from that as a fuel for powerplants. Do you suggest that it's time to revisit that Fuel Use Act, and that the efficiencies are so great now that we can afford to use natural gas as a fuel for an extended period of time?

Dr. **Williams**. I think this should be regarded as a premium use of natural gas. I think it's a crime to be using natural gas in steam electric powerplants, as they are today, at the very low efficiencies that are characteristic of those plants, and I would not release the pressure on moving away from the use of natural gas in those powerplants.

And I'm not sure that I would say that it's time to do away with FUA. I think that it is important to put this capacity on line with the capability of making a shift to an alternative fuel if that is necessary, if and when that is necessary. I think that that kind of flexibility is very important for the technology. And with the technology that's been developed by G.E., that flexibility exists.

Senator **Evans**. Would you suggest perhaps a modification of the act to allow use of natural gas as a fuel if you can achieve some particular level of efficiency or go below a certain level of fuel use per production kilowatt hours?

Dr. WILLIAMS. I don't know. I tend to favor market criteria more than——

Senator EVANS. Yes, but we can't use market criteria if we prevent the use of that as a tool.

Dr. WILLIAMS. That's right. Yes.

Senator EVANS. I thought I understood you to say that you wouldn't suggest that we would abandon it entirely. I'm trying to get at where——

Dr. WILLIAMS. I'm thinking that some modification probably should be considered. I don't want to make a specific suggestion as to what that is.

[Subsequent to the hearing Dr. Williams submitted the following:]

Princeton University
School of Engineering/Applied Science
Center for Energy and Environmental Studies
The Engineering Quadrangle
Princeton, New Jersey 08544
Phone (609)452-5445

July 31, 1985

The Honorable Daniel J. Evans
702 Hart Senate Office Building
Washington, DC 20510

Dear Senator Evans:

In this letter I offer a more carefully considered response to your question at the July 25 "Oversight Hearing on the Potential for Serious Regional Shortages of Electric Power in the United States by the Early 1990s," as to whether the time has come to repeal or amend the Powerplant and Industrial Fuel Use Act of 1978. As indicated by my equivocal answer at the Hearing, I have mixed feelings on this question. On the one hand, I think that the Act has the value of setting a timetable for shifting electrical utilities from their present wasteful use of gas (mainly in steam-electric thermal power plants), which accounted for 18% of total US gas use and 12% of total US electricity production in 1984. On the other hand, the Act inhibits uses of gas which are both energy-efficient and economically-efficient, as would be the case with the steam-injected gas turbines I described in my testimony.*

You asked if I thought that the Fuel Use Act should be amended, allowing the utility use of gas via technologies that meet some mininum energy efficiency test. While such an amendment may help promote efficient gas use by utilities, I think it is unwise for Congress to be involved with such narrow technical issues. An energy efficiency criterion may introduce other distortions (e.g., in itself it would not encourage efficient use of capital). Also, a threshold efficiency may also not be a very strong incentive to innovate, as the standard setting process would probably lead to a threshold set at a sufficiently low level to permit a wide range of vendors to compete for the new equipment. While a minimum efficiency standard might be an improvement on the Fuel Use Act, I think there are more promising alternatives.

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* The use of a power generating technology with an efficiency of the steam-injected gas turbine would represent a more energy-efficient use of natural gas than the direct burning of natural gas even for so-called "premium" applications" like space heating. For details, see the attached note on the energy efficiency of space heating via direct and indirect use of gas.

I think it would be far preferable to repeal the Fuel Use Act and to simultaneously enact a new federal initiative that would encourage public utility commissions to reward utilities for economic efficiency. Since steam-injected gas turbines would probably be able to produce power at a lower busbar cost than that for electricity generation via new coal or nuclear plants and also at a lower busbar cost than the fuel cost associated with continuing to operate steam-electric plants fueled with natural gas, a reward to the utility (e.g., a higher rate of return) for improved economic efficiency would encourage utility use of this technology (even to the extent of motivating early retirement of existing steam-plants fired with natural gas in favor of building steam-injected gas turbines) along with other economically efficient technologies as well (including cost-effective investments in "saved energy"). The reward to the utility would be a way of sharing the savings arising from improved economic efficiency between the ratepayers and the utility stockholders.

For the longer term the suggestion at the hearing by Mssrs. Siegel and Sillin to move toward deregulation of power generation should be given serious consideration, because the original motivation for the regulation of generation is no longer valid.

The basic idea behind regulation is the belief that the provision of electricity represents a natural monopoly. The natural monopoly concept is that whenever unit costs decrease as the plant size is made larger, there are inexorable cost pressures forcing dominance by a single firm -- a natural monopoly. Under these circumstances the consumer is served best by granting a single firm a geographical monopoly and by regulating the utility to ensure that the consumer is protected from monopolistic abuses (e.g., monopolistic prices) and that the natural monopoly is allowed a fair return on its investment.

Both cogeneration and central station power generation based on the steam-injected gas turbine are examples of relatively small-scale power sources that can compete with large-scale central station plants. Moreover, with today's transmission technology it is possible to serve any particular need for power by generating facilities dispersed over a wide region. Both of these technological developments undermine the original rationale for the regulation of electric power generation.

But the rationale for continued regulation of transmission and distribution remains strong. Duplication of transmission facilities would be very wasteful. Similarly, distribution technology represents a natural monopoly in a particular community.

In fact, a case can be made that any moves toward deregulation of generation should be accompanied by increased regulation of transmission to promote wheeling. The American Public Power Association memorandum "Electric Transmission in the US: Problems and Solutions" attached to Larry Hobart's testimony in this hearing discusses in detail the many problems inhibiting wheeling at present. Both stronger interconnections and broad access to transmission lines at just and reasonable rates are needed if deregulation of generation is to lead to improved economic efficiency -- requiring a more active FERC role in this area or perhaps even a new layer of regulation at the regional level (perhaps by regional bodies that have broad regional utility planning responsibilities, such as the Northwest Power Planning Council). In any case, any moves toward deregulation of power generation should be made cautiously.

Once again, I appreciate the opportunity to have been able to participate in this important Hearing and request that this letter be appended in the record to my written testimony. I also request that the enclosed edited version (dated July 30) of my testimony be substituted for the written testimony I submitted at the Hearing.

Sincerely yours,

Robert H. Williams

Robert H. Williams
Senior Research Scientist

Note on the Energy Efficiency of Space Heating Via the Direct and Indirect Use of Gas

Consider the gas resource requirements to provide 1 BTU of delivered heat both via direct use of gas in efficient furnaces and via electricity derived from gas in steam-injected gas turbines.

For heating with gas directly the input gas required to provide 1.0 BTU of delivered heat is given by:

1.0 BTU of heat / (gas furnace efficiency) / (gas T&D efficiency).

The average gas transmission and distribution efficiency for residential customers is 0.887 (American Gas Association, January 26, 1979), and the most efficient gas furnace now available is a condensing gas furnace for which the efficiency is 95%. Thus 1.19 BTU of gas input is required to provide 1.0 BTU of delivered heat.

With electric heat the input gas required is instead:

1.0 BTU of heat / (heating system efficiency) / (electric T&D efficiency)

/ (efficiency of power generation)

/ (efficiency of delivering gas to electric utilities)

The average efficiency of delivering gas to electric utilities is 0.915 (American Gas Association, January 26, 1979), the efficiency of power generation with steam-injected gas turbines is 0.50, the average electric T&D efficiency for residential users is 0.912, and the seasonal average heating system coefficient of performance (COP) in a typical climate with the most efficient heat pump available today is 2.6 (American Council for an Energy Efficient Economy, July 1985). Thus the amount of resource gas required to provide 1 BTU of delivered heat is 0.92 BTU, about 1/4 less than what is required with the most efficient gas furnace. In fact, the breakeven gas resource input would occur for a heat pump with a seasonal average COP = 2.0, a value which is exceeded by many heat pumps on the market today.

References

American Council for an Energy-Efficient Economy, "The Most Energy-Efficient Appliances," Washington DC, Summer 1985.

American Gas Association (Policy Evaluation and Analysis Group), "Comparison of a Balanced Residential/Commerical Energy Economy Versus an All Electric Residential/Commercial Economy," Arlington, Virginai, January 26, 1979.

Senator **Evans**. Mr. Gent, you talked about the aggregated forecasts of the various utilities in the council. Do you try to forecast on—you know, the aggregated forecast gives you one set of results. Do you try to use alternative methods of forecasting to check that out, or do you depend entirely on the aggregated forecasts of your individual utility members?

Mr. **Gent**. We do use the aggregated forecast and try to develop bands around that, as the testimony says. We do go back, in this case, to 1950 and try our own forecast to make sure that it's credible back through those years.

But the forecast that we present as a point forecast when we talk about 2.2 percent is the aggregation of all the electric utilities in the United States and Canada.

Senator **Evans**. It seems to me we used to use aggregated forecasts in the Pacific Northwest for some period of time; in fact, right up to virtually the time that the Pacific Northwest Power Council came into being and found that that's a pretty crude way to do things. And the utilities have moved away from that. They still collect it, but they really work in an entirely different way now.

Just taking our own part of the country as an example, and I don't know if it can be translated to the rest of the country, but I suspect it might—if you aggregate all of the utilities' expectations for the future, it seems to me you have a builtin bias toward too much; that more than one utility will expect to get a major industrial plant; more than one utility will expect to get a substantial share, an unusual share of the growth of that particular region or area. And they're not all going to get it, but they all predict it.

And they all have to predict it individually, but collectively it seems to me, and it seemed I think finally to the people in the Northwest that it tended to overstate the case.

Mr. **Gent**. There are two comments to that. The Pacific Northwest is somewhat of a homogeneous region where the characteristics of the region are unique to that region. There are other regions in the United States, for instance, in New England where they have a council with some similarities to the one you have in the Pacific Northwest, where they also do their top-down econometric forecasts for the entire region.

Your statement about always overestimating was true until about 5 years ago. We, I think, now have some utilities that deliberately forecast to what they can financially afford, and it generally comes out to be quite a bit lower than some of their neighbors.

Senator **Evans**. Mr. Sillin, I understand that you shortly have to appear before a House committee to go through another interrogation. I don't envy you the double-header for the afternoon, but any time you feel you have to go—and any other members of the panel—it's been a fascinating and very useful panel and I appreciate everyone's attendance. But any time you have to leave, feel free to do so.

Mr. **Sillin**. Well, I guess this is as good a time as any for me to exit, Senator. I want to just say I really enjoyed it very much and I thank you very, very much for inviting me. And thank you again.

Senator **Evans**. OK. I expect that we may even have, as we sort through everyone's testimony and get an even better command of it, we may have some additional questions that we'll want to come back at you with.

But let me continue. Mr. Gent, on page 17 of your testimony, you talked about shortening lead times, and I thoroughly agree with you that a reduction in the amount of time between commitment and operation of a generating unit would be of great benefit in capacity planning.

It seems to me that that's also reflective of what remains today as the greatest unknown cost for utility—electric utility planners—and that's the lead time, the risk time between proposal and production of electricity. And anything we can do to shorten that lead time can be helpful.

It seems to me that there is one area where Congress can act to at least try to simplify and streamline regulatory activities as they relate primarily to central station plants. But if a prudent utility manager understands that, and if you agree that that is a major risk for anybody planning for the future, doesn't it—you go on to say that smaller units are being considered as a mean of shortening the time between commitment and operation and reducing capital requirement.

In a number of cases, do you believe now that those smaller units may well turn out to be, taking risk into consideration, the least cost method of acquiring new generation?

Mr. Gent. Considering the uncertainty, I think that that's the only option we have left to us is to wait until the very last moment when something is needed and then everybody agrees it's needed, and then hope we can build it on time.

There are several research projects, that I'm sure others before me have stated, underway to make smaller units, sort of a mold out of a cookie cutter, so to speak, so that a lot of the work can be done in the shop instead of the field, or there doesn't have to be so much site-specific work done. And that's possible with the smaller sized units.

Additionally, in addition to the steam injection, there is fluidized bed construction which many hold out to be the panacea of the acid rain problem in the years to come. Those will all be smaller units because of the risk.

Senator Evans. Well, it seems to me that we embarked on a course where we thought bigger was better and cheaper, and at least in many cases got burned, and a lot of that was because of the uncertainty of time that took us through those cliffs and valleys of interest rates and construction cost increases, plus regulatory impediments.

To what degree—you've mentioned that utilities may want to wait until the last minute, until everyone agrees something is necessary, and then you go with the shortest lead time facility. That's sort of emergency planning.

Does it make sense for a utility to do that on a more stable basis? Just considering the future, look at that as a regularized part of keeping the necessary reserve margin that will avoid that kind of emergency, and opt for a regular system of smaller and more unitized generation plants?

Mr. Gent. Senator, if we could do that, then we would have a sure view of the future. And if we could all agree as to what the future would be, then we could build a larger, cheaper unit to meet that future.

Senator **Evans**. Yeah, but we don't have that.

Mr. **Gent**. But we don't have that.

Senator **Evans**. So with that uncertain future, what makes the most sense and will end up as generally being the least cost and the safest, I guess, financially?

Dr. Williams?

Dr. **Williams**. I have a suggestion of one thing I think would be very important for the steam injected gas turbine in terms of the policy initiative. And that is that there's presently an excess capacity in most parts of the country that's going to persist for several years. And so the demand for this technology, despite my colleagues' expectation here that they think the demand is going to grow 4 or 5 percent per year, I don't think that's going to happen. And if you're going to bring this new technology to market and G.E. says they could, if there's adequate interest in it, they could make it commercially available by 1988, I think that a very good initial market would be to back gas out of the existing steam plants in the country and create an initial market for this technology with that particular activity.

As I showed in my testimony, almost irregardless of when a steam gas plant was built, it would be worthwhile to scrap it and replace it with one of these steam injected units because the total cost, annualized capital cost plus the operating cost, would be less than the fuel cost of continuing to run these plants.

Senator **Evans**. So you would suggest that a utility today may have already depreciated virtually all of an existing gas turbine or oil-fired turbine plant?

Dr. **Williams**. These are steam turbine plants I'm talking about——

Senator **Evans**. All right.

Dr. **Williams** [continuing]. For baseload power.

Senator **Evans**. Yeah. But a current steam generating plant that's fired by either gas or oil, are you saying that these new units, a collection of however many were necessary to equal the electric output, would be a prudent investment currently and that utilities——

Dr. **Williams**. It would not only be a prudent investment after the depreciated life of the system is over, but even if that were not the case, even if the plant still has 10 or 20 years of life left in it.

Senator **Evans**. Why isn't everybody jumping to the bait? It seems to me if that's true, and if utilities understand it to be true, they'd be knocking the doors down.

Dr. **Williams**. It requires a capital investment. A 100-megawatt plant costs $50 million, for one thing. And the technology is targeted to be, you know, if there's interest n it, to be commercial in 1988. This was really not analyzed in great depth until the last couple of years. This is really a new old technology. It's an old idea, but it was never really considered seriously for central station power generation, largely because during the decade of the 1970's when much of the R&D on aircraft derivative gas turbines from which this technology derives was going on, there was very little interest in stationary power generation based on gas turbines because people thought that the gas supplies were rapidly drying up, and it wasn't really looked at in any depth at all until very recently.

Senator **Evans**. It sounds to me like you're describing the chicken and the egg. How would you suggest, then—obviously, they're not going to continue to bring it on into production unless there are some sales. Nobody is going to buy it until it's ready to produce.

Dr. **Williams**. I would suggest measures aimed at encouraging the retirement, even the early retirement of gas-fired steam powered generation.

Senator **Evans**. You suggest that might be a better investment for some of our synfuel money than some of the synfuel operations?

Dr. **Williams**. I think this can be done. I don't think public money is necessary for this.

Senator **Evans**. That's even better.

Mr. Beyea, what do you think of the proposal of actively considering in essence an open market, the utility going out and purchasing added efficiencies from wherever they can get them from—from industrial plants, from homes, from commercial establishments?

Dr. **Beyea**. Well, its certainly a very exciting idea. Parts of it are very exciting, especially the purchased electricity part of it. I guess I'm a little nervous about total deregulation of electricity sales because I wonder how you regulate nuclear powerplants under that situation. And I wonder about the regulation of air pollution.

Senator **Evans**. Are you talking about regulation as far as safety and environmental considerations are concerned?

Dr. **Beyea**. That's right.

Senator **Evans**. Well, I think that's possible to do. We regulate aircraft safety and a whole lot of other things while we've deregulated the airline industry. So I think you can separate those.

Dr. **Beyea**. Well, you may have a little more confidence in that than I do.

Senator **Evans**. How often do you fly? We have some confidence in flying.

Dr. **Beyea**. So you're suggesting that if we deregulate the nuclear power industry, that the safety record would become——

Senator **Evans**. I haven't made that suggestion. Some of the other panel has. But I'm just saying that I think that it's possible, even when you deregulate as far as price and availability and sales of power generator is concerned, you could, I think, effectively still maintain the necessary safety and other requirements. I think those are two separate things.

Dr. **Beyea**. I think I have to disagree on that one. But I think in the other areas, there are areas where deregulation would be very useful and perhaps, with time and study, that I might agree with you on the deregulation aspects of nuclear and coal.

Senator **Evans**. Dr. Naill, you mentioned in your least cost strategy, which I found not only interesting but the same terminology we were using in our Pacific Northwest planning operation, and that's really what we eventually came down to, was what we figured was the least cost strategy, which was a combination of trying to measure the actual cost of whatever kind of new electric production there was, taking into account the risk of time and trying to reach some sort of balance so that you have a combination of the lowest cost and the least risk.

Is that the essentially the strategy you suggested is useful?

Dr. NAILL. I'm familiar with the Pacific Northwest. We currently have Bonneville Power Administration as one of our clients and also Pacific Power & Light. I'm also familar with some of the work that you may have been involved with, which was the planning council produced in 1983, I believe, a document that I think, as I mentioned in my testimony, that I think has some very exciting ideas for how to do planning in an uncertain environment.

And the point that I mentioned was options. The idea is to try to shorten the lead time of some of the—if the lead time is the real culprit in some of this planning, we have all agreed that uncertainty is inevitable and what do you do if you're a planner, a utility planner and you're faced with this uncertainty? Well, one of the things that stabilizes the system, that makes his job easier, is to have shorter lead time resources.

And the Pacific Northwest has adopted a policy of—or at least is experimenting with a policy that tries to shorten those lead times by implementing what they call options, where essentially the idea is to—if you think there's a need for a coal plant or a wind facility or hydropower facility, you would do the front end, the long lead time front end work early, even though there's some risk that that may not be needed so soon. You would site it, you would go through the processes of getting the permitting and the siting to the point perhaps right up to construction.

If you look at the expenditure curve of a lot of these facilities, that work for the front end, the first 2, 3, 4 years of those plants is not very expensive. It may cost a couple million dollars compared to a total cost that might be in the billions of dollars.

Senator EVANS. That was a concept that—in fact, I chaired the Council when we developed it.

Dr. NAILL. It was a good idea.

Senator EVANS. But it does require a good deal of changed thinking and some changed regulation.

Now, I'd like to ask a question to Dr. Beyea along that line. You know, that concept was to reduce that risk of time and as I remember the figures, the coal plant was a 10-year lead time, had about 6 years into the precontruction phase, and 4 years in construction. But that 6 years only cost about 9 percent of the total eventual capital cost of the project.

So at further low cost, you could reduce the risk of time quite substantially. And the whole idea at that time was if a utility sponsored something like that, got right up to construction time, and it was felt that it was not needed at that point, that you look 4 years ahead and say, look, we can't even sell the damn power, so we ought to delay it. At that point, Bonneville—and we have the capacity through the Northwest with the Bonneville Power Administration to purchase that investment. And the utility becomes neutral as to whether to move ahead on construction or not; where, if you don't do that, they have all of the—you know, they have to move ahead and construct. It's the only way they can get their investment back.

Now, what that requires is that you go through all of the environmental requirements and you meet all of the regulatory requirements and you're ready for construction, but then you have to hold that for some period of time, maybe several years.

Do you object to that?

Dr. **Beyea**. No. I think that sounds like one sensible way to deal with this problem. I must say that we would be delighted to have the Northwest Power Planning Council replicated across the United States. We wouldn't have so many problems from our perspective if the kind of approach was taken everywhere that was taken out there.

Senator **Evans**. Let me make sure I understand, because there have been some who suggest that well, we're a little antsy about that because if you meet all of the requirements up to the year zero and then you delay and for 3 or 4 years you do not build the plant—and they say, well, something might happen in the meantime to bring new requirements for environmental or other controls, new regulations. You still favor that option that maintains the approval that was once there, but continued through that freeze period?

Dr. **Beyea**. I realize that that is not a unanimous opinion in the environmental community, but if the time—how many years are we talking about? Are we talking about 4 years?

Senator **Evans**. I think obviously you have to put some limits on it. You would have to say, yes, we can delay 4—some agreement—maybe it's 3 years, maybe it's some level of years, but if it gets too far, then obviously I think it makes sense to have to take some revised look.

Dr. **Beyea**. Let me say if that were in the context of an overall sensible energy policy, that I certainly and, I assume our organization, would be willing to go along with that as a reasonable compromise.

Senator **Evans**. Mr. Siegel, you didn't mention much about efficiencies. You concentrated more on the construction of new centralized powerplants.

What do you think of the idea of utilities seeking out industrial conservation, for instance? I think we're all familiar with what we can do in residential and maybe even commercial, but there seems to be much less available knowledge on industrial conservation.

It seemed to us in the Northwest Power Planning—I guess the best way to equate it is to suggest it's the same as an airline overbooking, as I mentioned this morning. When they overbook and they've got too many passengers, they go aboard the aircraft and say, we'll offer you 75 bucks to get off and give your seat to somebody else who's stranded, and they keep upping the price until somebody gets off and the thing balances.

Why not take the same kind of approach toward acquisition of electricity that you offer—well, offer to buy electricity, buy savings from an industrial plant? That seems to somehow not ring true to a whole lot of people. They say, you mean you're going to go out and pay some big industry to help improve their processes on which they'll make profits? That just doesn't sound right.

Does it sound right to you?

Dr. SIEGEL. The situation you just described with the airlines, basically a shortage where their planning, purposely or not, created a situation where they couldn't provide a service—maybe that's the least cost way to do it so that they don't need to buy another airplane.

On the other hand, you know, maybe that's not in the consumer's best interest if you have to shut somebody's electricity off, for example.

The notion of buying efficiency, I'm not an expert on it. John Sillin's and my approach to the entire question not only of demand, but also the solution to prices, is the free market system in this country. And in terms of if an industrial customer is looking at a price for electricity, he can make that decision whether it's in his financial interest to make a capital investment, to substitute capital for energy basically.

Senator EVANS. But there are two players in that game. And it seems to me there—in fact, we've got a perfect example in the Pacific Northwest right now. A major industrial customer, probably incapable of alone making an investment that would have the effect of reducing the electrical loads substantially, and so it may not happen.

But if the Bonneville Power Administration, or a utility for instance were to go to that company and say, look, we'll pay you $500 per installed kilowatt, or $1,000 or some figure that represents a cheaper way of getting electricity than they can get, then suddenly what is not worthwhile for the industry is worthwhile for the industry. They can go ahead and do it. And it's also worthwhile for the utility.

Doesn't that make good sense?

Dr. SIEGEL. Yes, if it's cost-effective. Absolutely. I would only caution you on two points, though. I think that trying to take a look at what's happening in the commercial sector, there's just a tremendous increase in demand in spite of various social suggestions of saving energy. So it will help you, but for how long I would caution.

Second, to the extent that you increase, you shave your peak load, you discourage demand at peak times, so you don't need to have extra available capacity, what you are doing simultaneously is increasing your load factor. What you're doing is driving down your unit cost. Therefore, electric prices in general ought to be declining in real terms, and there's this feedback. Price elasticity works both ways.

Senator EVANS. I even hate to end this, but if I don't get over to the floor, at another energy session, the question of fuel efficiency of automobiles, I wouldn't be doing my job.

And that brings up one final comment, I guess—the whole question of how far can you go. I think it's conceivable, for instance, just taking the automobile industry, the moving fleet we have in this country, we've seen over the past 10 years the fuel efficiency standards, a very, very large increase in the number and the miles moved with virtually no increase—in fact, some decrease in most of those years—in the amount of fuel used. And how far can that continue?

It seems to me the one thing we are missing, and I know it's very difficult to quantify as you look ahead, but one thing I don't think there's been talk about very much here are those yet-to-come technological improvements which I would be willing to be on, although I can't quantify them yet, that will help us considerably in the future.

If we get to the point where there are no more further technological improvements, we've certainly failed as a country, and I can see, for instance, the automobile fleet perfectly—you know, we don't know, technologically, if we're aggressive about it, how to build automobiles—and I don't mean tiny automobiles; I mean big, comfortable automobiles, 30, 40, 50, 60, and 70 miles per gallon. I think that we could easily have an automobile fleet that would use no more fuel than today and have double the number of cars on the road 20 or 30 years from now.

And I think maybe the same sort of thing can happen electrically.

Bob?

Dr. **WILLIAMS**. I'd like to make a comment, just to follow up that observation. And that is that, since as you've seen my approach to this problem is an end use approach, one of the things that I do is track very closely the introduction of new end use technologies in residential, commercial, industrial areas. And one thing that is very interesting to observe is that we've lived with central power generation, you know, for 100 years or more, but the age of energy efficiency is just a little more than a decade old, and it takes on the order of a decade for new technology to come out of the laboratory.

And what is very interesting is that if you look at the introduction of new products, more energy efficient end use products, and the rate at which they come out, most all of what underlies my analysis has come available onto the market since 1980-81, and the rate of introduction of new products by brand and what-not has been increasing exponentially at a very rapid rate in this area, and we see all kind of new things that are just sort of around the corner that go even further.

The ones that I mentioned in my testimony, you know, that's based on data that has just recently become available, some new appliances that have come out in 1984 and 1985. This adds another enormous amount of uncertainty into this long-range planning, is where is all this going to end? And there is no obvious constraint on slowing this down in the foreseeable future.

Senator **EVANS**. We all have the problem of trying to define what the next generation's technology is.

I guess the final note, the man who brought us all of this in the first place—Thomas Edison—could never bring himself during his entire lifetime to believe that alternating current was ever part of our future.

We now are ready to excuse this panel and call the next panel before us. And thank you very, very much. It's taken an extended amount of time, but it's been very, very helpful to us.

The next panel is Mr. Ken Davis, consultant, Bechtel Power Corp., representing the American Nuclear Energy Council; Mr. Douglas Randall, senior vice president, Standard & Poor's Corp.;

and Dr. John Anderson, executive director, Electricity Consumers Resource Council.

Mr. **Doane** [presiding]. For the record, my name is David Doane. I am senior counsel on the staff of the committee. To explain this situation, Chairman McClure had intended to chair the remainder of this hearing. However, because of an unavoidable last-minute conflict—which is not uncommon—he will be unable to chair, be unable to be here for the remainder of the hearing.

No other member of the committee is available to chair; therefore, I have been asked to continue the hearing and to receive the oral statements from the remaining three witnesses.

Mr. Davis, welcome back to the committee. And you may proceed with the statement. Your entire statement, of course, will be put into the record in full and you are certainly free to summarize in your oral testimony.

STATEMENT OF W. KENNETH DAVIS, CONSULTANT, BECHTEL POWER CORP., ON BEHALF OF AMERICAN NUCLEAR ENERGY COUNCIL; ACCOMPANIED BY ED DAVIS, PRESIDENT, AMERICAN NUCLEAR ENERGY COUNCIL

Mr. **Davis**. Well, thank you very much. I'm very pleased to be here and to have this opportunity to make a presentation on behalf of American Nuclear Energy Council, and I am accompanied here by Mr. Ed Davis, the president of the American Nuclear Energy Council. You're getting two Davises for the price of one.

I would appreciate it if you would convey to the chairman, Senator McClure, and the other members of the committee, our compliments on having these timely hearings on this critical subject. I think it is evident from what at least I've seen already, that they are revealing a changing situation which is critical to our future and which must be dealt with constructively and objectively at both the Federal and State levels.

My qualifications and appropriate data on the American Nuclear Energy Council are included in the prepared testimony, which I understand you will include in the record.

You have heard many views on the anticipated growth in demand for electric power, and we subscribe to the estimates for planning purposes on the order of 3-percent per year in the next decade. There are, with respect to this, several points which I think need to be stressed.

First, we cannot afford to run the risk of the availability of electric power becoming a constraint on economic growth or a detriment to national security. The use of electric power is not just a consequence of economic growth; it is one of the vital ingredients in achieving it.

Second, even we felt we could predict the rate of increase in demand accurately, which we cannot, it still would be prudent planning to be somewhat on the high side, since the penalties for shortfalls exceed the cost of some excess capacity and, as already noted, projects can be slowed down more easily than they can be accelerated.

Third, the general expectations, as related by the other witnesses with respect to growth, well exceed the 2.2-percent per annum forecast of available capacity made by Mr. Gent of NERC, which as he pointed out, included the rather unlikely assumptions that all the planned units will be finished on schedule, including some of those which have not yet been ordered, and that no units will be retired.

Another important point with respect to this is that this is a national average which does not reflect local situations and this, I might add, is also true of many of the other presentations which you have heard.

Before turning to the subject of nuclear power, I would like to make some comments on the conditions under which new major generating units might be ordered by the utilities. First of all, the conditions of the contract between the utilities and their PUCs need to be changed. The principal objective is to agree on the conditions before the fact, not afterward, based on 20/20 hindsight. Some of the items which might logically be included are the following:

No. 1. Concurrence that the forecasts of growth are a well justified basis for planning.

No. 2. Agreement that new capacity is necessary on the utility's system to meet the needs.

No. 3. Agreement on the site selected for the facility;

No. 4. Concurrence on the type of generating unit or units chosen and the basis for their selection and size.

No. 5. A firm agreeement, essentially a contract, that if the units are built in a business-like way, and despite unpredictable and uncontrollable outside events, NRC or others, the costs of units will be introduced into the rate base on a known and predictable basis. This would not be left for hearing and decisions after the plant is completed.

No. 6. Concurrence with the contracting arrangements, choice of contractors, and with the overall plan for obtaining financing even if this is not done on a project basis.

No. 7. I would include public understanding or support of public understanding for the program.

No. 8. Similar assurances to those financing the construction program for the utility.

A further very important point which was also mentioned by Mr. Boggs is the need to change the accounting system to levelize the cost rather than have the enormous front-end loading as at present, which is one of the main contributors to rate shock.

The other related issue is construction work in progress which, if introduced generally, could also alleviate the rate shock problem.

Mr. Boggs has described well the fact that utility-type accounting would be untenable in a competitive market such as the automotive industry.

Another issue I have elaborated on in my testimony is the desirability in joint ventures, acquisitions and mergers in the electric utility industry to first reduce the enormous fragmentation where we have dozens of large utilities and hundreds of small ones; second, to provide effective national utility leadership; and third, to improve the management, financial, technical, and operating efficiencies of the utilities.

While there are a variety of mechanisms, some requiring changes in legislation, both Federal and State, this is a key issue in today's world of high technology powerplants and systems.

I would like to turn to the potential of nuclear power to provide a substantial part of our need for new generating capacity. There are several key issues. The first one I'll touch on is economics. A great deal of attention has been focused on the very high costs of nuclear plants recently completed or nearing completion, and these costs are claimed by some to be the real costs of nuclear powerplants.

Nothing could be more absurd. These plants have not been finished for more than 11 years after they were ordered because they have all had problems of one sort or another. This has occurred during a period of extraordinarily high construction inflation rates, which have been higher than the Consumer Price Index, and record interest rates.

While the costs are real for the units in question and pose a very difficult problem to the owners, they are not representative of what it would cost to license, design, and build a new nuclear powerplant under orderly and businesslike circumstances, if such can be achieved.

Very similar nuclear units have been constructed in other countries in periods of 4 to 6 years. These include France, Japan, Taiwan, and Korea. These countries basically adopted the U.S. safety standards and licensing framework, but implemented in a different manner. Nevertheless, their plants are running safely and more reliably, with higher availability factors than similar plants in the United States.

The principal difference is that we have a licensing system which not only requires an excessive amount of time to carry out the process, including preparation, reviews, hearings, and decisions, it is also subject to public interventions as well as legal delays at every turn.

The NRC has rapidly escalated the number of design requirements as they made changes at every turn, especially after the TMI II accident. Other requirements, such as emergency evacuation drills and so forth have also been introduced.

In addition, a necessary if not sufficient condition for nuclear powerplants is a reformed nuclear licensing process which generates confidence that once a license is applied for, it will be decided in a reasonable and predictable length of time; that, once issued, the construction can proceed with little chance of delays by interventions for backfitting and so forth, and that once the plant is completed, it can be put into operation in an orderly manner, perhaps without additional hearings or licensing actions under the concept of the combined construction and operating license.

Some of these steps can be and are being taken by the NRC by administrative action. Others, such as combined construction and operating licenses require changes in legislation, and others fall in a grey area where legislation would probably help assure needed reform.

One of the key concepts which has emerged is that of standard-

One of the key concepts which has emerged is that of standardized plants. More can and should be done to standardize plants.

Senator Simpson's Subcommittee on Nuclear Licensing held hearings on this subject on July 11, 1985, and I testified at that hearing and I have summarized in my prepared testimony the principal points that I made at that time, and will not take the time to read it here.

It is also important to see the Price-Anderson Act continue to provide the public protection which cannot be supplied by the utilities or their suppliers. While some changes may be necessary or desirable, the basic principles seem sound, both for Government contractors and the nuclear industry.

It is also of key importance to see TMI I started up again, essentially as a test of common sense and the credibility of the licensing process to the electric utilities.

In addition to positive leadership from the various segments of the electric industry, nuclear and conventional, there is a great need for recognition of the urgent problems of electricity supply and its relationships to the future health of the economy and the penalties for failing to solve the problems expeditiously. In that respect, I think these hearings are a major contribution.

It has been suggested that the matter is of sufficient importance that the President should make it a subject of a television address or an address to Congress. Unfortunately, it has been difficult to get the necessary level of attention, since there are few immediate problems; the problems are in the future if we do not do something immediately.

The American Nuclear Energy Council, along with many other organizations including the Edison Electric Institute, the Atomic Industrial Forum, the American Public Bar Association, the National Association of Regulatory Utility Commissioners, the National Rural Electric Cooperative Association, Scientists and Engineers for Secure Energy, has recommended the establishment of a Presidential commission on electric power to try to meet this need and facilitate the solution to some of the problems.

Such a commission, if given an appropriate charter and membership, and if it could act expeditiously, could make a valuable contribution to broader understanding of issues in electricity as well as nuclear power, and could be effective in recommending effective action. It would be important that such a commission not be utilized as an excuse for delaying important and urgently needed actions.

This concludes the remarks, which are really a summary of my prepared testimony and conclusions, and I would be glad to answer any questions you might have, and I may have some assistance from Mr. Davis.

Thank you.

[The prepared statement of Mr. Davis follows:]

PREPARED TESTIMONY
SUBMITTED BY
AMERICAN NUCLEAR ENERGY COUNCIL
PRESENTED BY
W. KENNETH DAVIS

TO THE

COMMITTEE ON ENERGY AND NATURAL RESOURCES
UNITED STATES SENATE
CONCERNING
U.S. ELECTRICITY SUPPLY AND DEMAND

JULY 25, 1985

U.S. ELECTRICITY SUPPLY AND DEMAND

Testimony to Senate Committee on Energy and Natural Resources

by

W. Kenneth Davis

on behalf of the American Nuclear Energy Council

Introduction

My name is Kenneth Davis. I am an independent consultant on management and engineering, representing the American Nuclear Energy Council (ANEC) of which I am an Honorary Director, in providing testimony to the Committee. I served as Deputy Secretary of Energy from 1981 until 1983. Prior to that I served as a corporate vice president of Bechtel Power Corporation and its predecessor companies for nearly 23 years and now serve them as a Consultant. Before that, I was Director of Reactor Development of the Atomic Energy Commission. At the present time, I am Chairman of the U.S. Committee for the World Energy Conference and Vice Chairman of the international organization. I have served as Vice President of the National Academy of Engineering, President/Chairman of the Atomic Industrial Forum, and President of the American Institute of Chemical Engineers. I am a Director of the Management Analysis Company and of the Atlantic Council as well as an Adjunct Professor of Engineering at the University of California, Los Angeles.

ANEC is a trade organization whose purpose is to promote the continued development and utilization of nuclear energy in a safe and environmentally acceptable manner consistent with the general welfare. ANEC member companies consist of over 100 organizations having an interest in nuclear energy — including investor owned, public owned, and cooperatively owned electric utilities; nuclear vendors; component manufacturers; architect-engineers; uranium minners and millers and fuel cycle organizations.

While I would like to discuss some aspects of the overall electricity situtation, I plan to focus my testimony on the factors involved in the future use of nuclear energy to meet our national requirements.

Historical Background

Let me state first of all that increased use of electricity (or of energy in general) is not just a consequence, some think an undesirable one, of economic growth but one of the fundamental resources for economic growth, a broader and higher standard of living, and improved national security. Wise and efficient use of electricity is desirable but we cannot as a nation afford to gamble on the adequacy of our future electricity supplies.

The era from the end of World War II until 1974 was remarkable since the growth in electric power demand was essentially constant at 7% per year. This was a period of rapid economic expansion and also of declining real prices for electricity (until 1970) as use increased, larger and more efficient generating plants were built, the distribution systems were strengthened, etc.

The OAPEC oil embargo of 1973-74 and the dramatic increases in crude oil prices controlled by the OPEC cartel brought us to a new era in all energy matters not only because of the high oil prices themselves (and resulting increases in prices for gas and coal) but also because of the massive impact that these prices had on the U.S. and worldwide economies including high inflation rates, depressions, high interest rates, and continuing unemployment.

The impact on the demand for electric power was sharp and devastating with the increase in the rate of demand growth dropping to 2.3% per year for the period 1974 to 1983. At the same time, the GNP increased at 2.1% per year.

At the end of 1974, the utilities which had not had any basic reason to anticipate such a large change in growth rate had on order 164 nuclear units (177 GW) in addition to the 37 GW of capacity then licensed for operation. This amounted to about 37% of the installed generating capacity (at the end of 1974). Since the utilities were counting on about half of their new capacity being nuclear and were estimating lead times of 7 to 8 years (because of growing licensing and equipment supply problems), this was just about what was required to meet a 7% p.a. growth rate. There were also a substantial number of fossil units on order but not in the same proportion because the lead times were substantially less.

As the reality of the decline in growth rate became acknowledged, the utilities found it necessary to cancel some orders (some with only small amounts of work done -- and some well on the way to completion), slow down the work on some of the units under construction, and in many cases to stop (defer) work on units even though well along.

Many of the units became the subject of prolonged and costly interventions, most had delays and increases in cost due to changes required by the NRC ("backfitting") especially after the TMI-2 accident in 1979, and all faced very high rates of inflation in construction costs as well as record rates of interest on the money invested. While many units were completed, many others have had and continue to have monumental cost and licensing problems.

Out of the 251 units on order at the end of 1978, a total of 123 have been cancelled or deferred, 94 have operating licenses, and 34 are still under construction or waiting for operating licenses.

The reason why there have been no new orders for nuclear power plants (which have gone forward) since the end of 1974 should be obvious -- there simply was no need to start any new nuclear projects.

While some fossil units have been ordered and completed (along with most of those on order at the end of 1974), there have not been many and there has been a "de facto" moratorium on any new generating plant orders for the past five years.

Even with the cancellation, deferrals, and slowdowns, there has been an adequate capacity margin. However, this is shrinking and combined with an increase in rate of growth in demand accompanying accelerating economic growth, it seems apparent that we are likely now entering a new era -- one where we need to be concerned about providing for adequate electricity suipplies in the future.

Future Needs

As you will have heard from Mr. Gent of NERC, their projections are that the present system and planned additions will support an increase in demand of 2.2% through 1994. This assumes that all nuclear units now under construction are put into operation as well as all planned fossil units, many of which have yet to be ordered. Further, it is an overall average and obscures problems in some geographical areas.

The increase in electricity sales in 1983 over 1982 was 3.1% (GNP up 3.3%) and for 1984 over 1983, 5.9% (GNP increase 6.9%).

While it cannot be asserted that there is anything except a historical relationship between GNP and electricity use (which may be decreasing), it must also be considered that it is anticipated by most business leaders and economists that the U.S. economy will grow at something like 3% p.a. for the next decade or so and some predict rates of increase up to 4%. Further, adequate supplies of energy and especially electricity can be a key factor in achieving such growth. With declining interest rates as well as oil prices, the impact of such forecasts cannot be ignored.

It is also relevant that the production of electricity consumes over 35% of all the energy used in the United States. This fraction has continued to grow steadily having been 27% in 1973.

A full consideration of these and other relevant facts including the length of time between a decision and operation of new generating projects even under favorable circumstances leads to the conclusion that prudent planning dictates the initiation of new generation projects in at least some geographical areas within the very near future -- certainly within the next year or two if shortfalls are not to become common by the early and mid-1990's.

It must be noted that the economic penalties of such shortfalls to the overall economy are estimated to be substantially greater than the cost of slowing down projects underway or of having some excess capacity before it turns out to be needed.

Alternatives for New Generating Capacity

While there are many situations where alternative energy sources such as solar, biomass, geothermal, wind, cogeneration, etc., can add to the energy supply or even the available capacity, the likely contribution of these during the coming decade on an economic basis is not likely to significantly affect the need for new coal and nuclear base load electric generating capacity. At 3% per year, by the early 1990's, the annual generating additions will need to be on the order of 20,000 megawatts.

Thus the "bottom line" is that the utilities should be ordering new generating plants on a limited basis within a year or two and on a wider basis after that. The only alternative and one frequently cited is the use of combustion turbines (gas or distillate) which can be constructed quickly and at a relatively low capital cost. However, they burn expensive fuel at a relatively low efficiency, present some environmental problems, and are not suitable for base load generation. Large-scale use of combustion turbines in place of base load generating facilities would certainly be disadvantageous.

For the foreseeable future the only two substantial potential sources of base load electric generating capacity are coal and nuclear. If they are able to, the utilities would generally like to minimize their risks by dividing their capacity between the two, particularly if the economics are in the same range. This raises the risks and problems inherent in coal-fired generation but I will not expand on these. Suffice it to say that they are significant.

Significance of Current Nuclear Projects

A great deal of attention has been focused on the very high costs of the nuclear plants recently completed or nearing completion and these costs are claimed by some to be the "real" costs of nuclear power plants. Nothing could be more absurd. These plants have not been finished for more than 11 years after they were ordered because they have all had problems of one sort or another. This has occurred during a period of extraordinarily high constructiion inflation rates (higher than the CPI) and record interest rates. While the costs are real for the units in question and pose a very difficult problem to the owners, they are not representative of what it would cost to license, design and build a new nuclear plant under orderly and businesslike circumstances if such can be achieved.

Very similar nuclear units have been constructed in other countries in periods of 4 to 6 years. These include France, Japan, Taiwan, and Korea. These countries basically adopted the U.S. safety standards and licensing framework — but implement it in a wholly different manner. Nevertheless, their plants are running safely and more reliably (higher availability factors) than similar plants in the U.S. The principle difference is that we have a licensing system which not only requires an excessive amount of time to carry out the process itself (preparation, reviews, hearings and decisions), but also is subject to public interventions as well as legal delays at every turn. The NRC has rapidly escalated the number of design requirements and has made changes (backfitting) at every turn — especially after the TMI-2 accident. Other requirements such as emergency evacuation drills, etc., have also been introduced.

However, it must be conceded that there have been cases of bad project management and execution which have led to delays and increased costs. Some utilities as well as vendors and suppliers may not have recognized the complexity of the projects they were taking on, particularly with the escalating NRC requirements. Also, some utilities did not have the cash to continue construction at an optimum rate and elected to proceed more slowly, particularly since the power was not needed as urgently as forecast due to declining load growth.

It is difficult to say precisely just what the costs would be for a new facility because most of those plants done in an orderly way were finished years ago and there has been little incentive to develop detailed cost estimates in the last several years because of the lack of any prosoects for new orders. Nevertheless, the studies done for the Department of Energy and others generally confirm that the economics of new nuclear power plants would likely be competitive with coal at least in most areas of the U.S. If the utilities confirm the possibility of new nuclear plant orders, then there should be new evaluations which will be more definitive.

Conditions for New Generating Capacity

Before turning to the issue of considering nuclear power for new generation, I would like to comment on the issue of new generating plants in general. The "generic" problem is often discussed as a financial problem, etc., but basically it seems to be one of a rather complete breakdown in the relations between the state regulatory agencies and the utilities, at least in the area of the construction of new plants. It seems doubtful that many utilities will be willing to undertake new plant construction without a change in that relationship. This, of course, varies greatly from state to state and also is affected by the Federal Energy Regulatory Commission (FERC).

Most utilities appear to be pursuing a "minimum capital expenditure" policy which they feel is consistent with the wishes of the regulatory agencies. Under conditions of sustained moderate growth as outlined above, such a policy is clearly the most expensive in the long run for everyone.

What sorts of arrangements might be made to change the nature of the relationships between the utilities and the regulatory agencies? It would seem that the most useful changes would be to set forth the basic agreements before a project is initiated rather than leaving key economic factors for after-the-fact decision as at present. The items which would seem to be important for pre-agreement include the following:

1. Concurrence that the forecasts of growth are prudent and well justified bases for planning.

2. Agreement that new capacity is necessary on the utilities' system to meet the need considering the time elements, interconnections, realistic estimates of conservation (improved efficiency), etc.

3. Agreement on the site selected for the facility. May (likely) be a site which already has generating units.

4. Concurrence on the type of generating unit(s) chosen and the basis for their selection and size.

5. A firm agreement, essentially a contract, that if the unit(s) are built in a businesslike way and despite unpredictable and uncontrollable outside events (NRC, etc.), the costs of the units will be introduced into the rate base on a known and predictable basis. This will not be left for hearings and decisions after the plant is completed.

6. Concurrence with the contracting arrangements, choice of contractors, and with the overall plan for obtaining financing even if not on a "project" basis.

7. Public understanding and support of the planned program.

8. Similar assurances to those financing the construction program for the utility.

While the extent to which such pre-agreement can be achieved or would be necessary will vary from one state to another, this would seem to be a necessary approach if new large generating units are to be built in the future. While the utilities may object that some of their management prerogatives are being removed, which indeed would be true, the advantages of being able to build a plant on an orderly basis and get it into the rate base in a predictable fashion should outweigh this. Another problem is how well the "agreements" would hold up with time under changing economic and political circumstances. After all, the electric utilities are supposed to be adequately compensated for providing a public service under present laws. However, a new mechanism might help in the real world.

Joint Ventures, Mergers and Acquisitions

One of the very real problems with the electric utility industry's ability to finance and build large generating facility is the very great fragmentation of it into dozens of large utilities and literally hundreds of smaller ones, several hundred if all of the investor owned utilities and coops are included. In large states there are often several large investor owned and public utilities as well as dozens of small ones.

In the high technology era for power plants: nuclear, coal, combined cycle, etc., this fragmentation does not seem satisfactory or workable in the long run. Various alternatives to the present arrangement are required to distribute the risk associated with the construction of technologically complex capital intensive generating facilities that are constructed over long lead times and often under changing conditions. The utilities generally have had to form associations and joint ventures to undertake and manage large projects but this has its limitations, many of them legal and managerial. Mergers by whatever means of smaller utilities into larger ones would do a great deal to improve operating efficiency (both from the systems and managerial points of view). It would consolidate scarce managerial and technical expertise and would strengthen their financial capabilities. Other innovative alternatives such as separate generating and transmission companies should also be considered.

Such combinations of utilities could do a great deal to provide and strengthen the leadership of the electric utility industry in national and local affairs. This is important when one considers that the generation and distribution of electric power is the most capital intensive large industry in the United States and that the production of electricity consumes more than one third of our energy.

Aside from the reluctance of many of the utility executives for understandable reasons to seek such mergers or acquisitions, there are a variety of federal and state laws which would need to be changed at least in most cases. However, some mergers are being discussed and more may come along.

While this is a legal area which I am not prepared to elaborate on, it seems to me that this, along with the relations with the state regulators, are the two key issues in maintaining a strong electric utility industry in this country.

Prospects for Nuclear Power

If we assume that the basic issues of prudent planning for future needs, relations with the state regulatory agencies, and assessments of relative economics lead to the conclusion that nuclear power should be considered as an option for new generating plant, what are the basic problems?

There are several but the largest hurdle, a necessary if not sufficient condition, is a reformed nuclear licensing process which generates confidence that once a license is applied for, it will be decided in a reasonable and predictable length of time; that once issued, the construction can proceed with little chances of delays by interventions, for backfitting, etc.; and that once the plant is completed, it can be put into operation in an orderly manner, perhaps without additional hearings or licensing actions (combined construction and operating license). Phased approval of construction and quality assurance as the project proceeds.

Some of these steps can be and some are being taken by the NRC by administrative action, others such as combined construction and operating licenses require changes in legislation, and others fall in a "gray area" where legislation would probably help assure needed reforms.

One of the key concepts which has emerged is that of standardized plants. While many of the components, materials, testing procedures for nuclear plants are standardized, as well as major systems such as the NSSS's, more can and should be done to standardize plants. This is a very useful concept if implemented in a rational manner. Senator Simpson's Subcommitee on Nuclear Licensing held hearings on this subject on July 11, 1985, and I testified at that hearing. Without repeating all of that, let me summarize the main points:

1. The utilities when they order the first new nuclear power plants will in all likelihood order units nearly identical to units already built and in successful operation. In doing so they will thus have essentially complete designs backed up by operating experience and this should minimize the risk.

2. In some cases, the utilities may want to re-start plants which have been deferred as the least cost way of obtaining added capacity.

3. In some cases, a utility may wish to duplicate a plant operating on their system even though not of the latest design in order to simplify training and operating procedures, duplication of equipment, etc.

4. Advanced and modified (improved) LWR designs as well as advanced reactors will likely not be proposed for the first generation of new orders because of the costs involved as well as the licensing risks.

5. All of the cases listed above should be accommodated in any licensing reform and legislation. The first three cases really lead to the selection of "referenced plants" and should lead to standardization as an evolutionary process.

6. There are two basic limitations to standardization. One of these is the adaptations of the standardized design to the specific site. The other is the need to preserve competition for systems, components, suppliers, etc.

7. The establishment and approval of basic systems (including instrumentation and control), modules, and major components should be the goal and would reduce the proliferation of new designs, new training programs, new operating procedures, and regulatory reviews. (This is the limit of the French standardization program as they have defined it.)

8. Flexibility must be maintained, however, to accommodate competition and in this respect, the U.S. requirements are very different from the French where they have one owner (EdF — which does its own architect-engineering and construction management work), one NSSS supplier, one T-G supplier, and one fuel cycle supplier. All components for a "series" (up to 18 reactors) are purchased at once from a single supplier. However, it appears that the basic components, systems, and portions of the plant, those directly related to reactor safety, can be standardized even more than they are today with sufficient flexibility to accommodate the competitiion desired by the utilities (and the Department of Justice). This can most easily be done with modules and systems which can be assembled into a complete plant design but which individually can allow for alternatives in the supply of physical systems and components.

9. The overall plant design must reflect the site conditions but most of these have little bearing on safety and can be reviewed as variations from a reference design. Those of significance such as seismic requirements can be treated in classes. Other features of sites which affect the overall plant design include foundation and geology, flood protection, fresh versus salt water conditions (and protection), closed versus open cycle cooling, orientation of water intake and discharge systems, power lines and switch yards, transport facilities, system electrical requirements, meteorological conditions, etc. While the ranges are less extreme, it is of interest that all of these factors have been considered in adapting the French standard models to their individual sites.

10. We believe that standardized designs can be defined in legislation only in the operative sense. Policies, procedures, criteria, specific findings, etc., can be set forth by law along with the uses of standardized designs. However, the interpretations, particularly those of a technical nature, will be a matter of judgment. These judgments should be carried out in an orderly and timely process by knowledgeable people backed up with sound techncial advice — pressumably the Nuclear Regulatory Commission.

11. We support measures for pre-approvals of sites for nuclear power plants since we feel this will be useful in the future.

12. We strongly support the concept of "phased approval" of construction and quality assurance as a project progresses.

13. We believe a combined construction and operating license procedure is essential and that it be compatible with the way we believe new orders will be initiated and the evolution of standardized plants.

14. We believe measures to constrain backfitting are very important and again are complementary to the standardization concept.

15. We favor the reorganization of the Nuclear Regulatory Commission to provide for a single Administrator appointed by the President (with the advice and consent of the Senate).

16. We also urge that full consideration be given to modifications to the "source term" by the NRC based on the data and evidence at hand.

There are, of course, other issues involved in the initiation of new nuclear plants. One often cited is the financial problems. However, many utilities are in better financial shape today than they have been for some time which is reassuring to the financial community. If the other issues dealt with here can be resolved so that construction of a new nuclear power plant can be viewed as a prudent business decision, then there seems little reason to feel that the needed financial support will not be available.

Public opinion is usually cited as another major consideration. It does not have a direct impact but can influence utilities, regulators, legislators, etc. However, the public seems about evenly divided on the subject of nuclear power plants, based on most opinion polls, and again, resolution of the other issues most likely would have a strong effect on public opinion.

In this regard, it is important to see the Price-Anderson Act continue to provide the public protection which cannot be supplied by the utilities or their suppliers. While some changes may be necessary or desirable, the basic principle seems sound both for government contractors and the nuclear industry.

There is also a necessity for adequate property insurance to cover the very large plant investments. This is being worked out by industry.

It must also be said that it is of key importance to see TMI-1 started up again, essentially as a test of common sense and the credibility of the NRC to the electric utilities.

Continued progress on the radioactive waste management program is also essential for much the same reasons. Not only are there practical problems of fuel storage but also questions of the credibility and the capability of the government to successfully implement this critical program.

The driving force behind the needed changes must be a conviction that nuclear power is important to the future of America. Those who must take the necessary actions, some of them politically risky or unpopular, need to feel that they are serving a timely and important purpose in doing so.

It is not realistic to expect them to do so if they only hear that the utility industry does not wish to or will not consider building more nuclear power plants. This has been the perception of many and it is critical that it be changed in a very positive way by the leaders of the industry.

National Leadership

In addition to positive leadership from the various segments of the electricity industry (nuclear and conventional), there is a great need for recognition of the urgent problems of electricity supply and its relationship to the future health of the economy — and the penalties for failing to solve the problems expeditiously. It has been suggested that the matter is of sufficient importance that the President should make it the subject of a television address or an address to the Congress. Unfortunately, it has been difficult to get the necessary level of attention since there are few immediate problems -- the problems are in the future if we do not do something immediately.

The American Nuclear Energy Council, along with many other organizations including the Edison Electric Institute, the Atomic Industrial Forum, the American Public Power Association, the National Association of Regulatory Utility Commissioners, the National Rural Electric Cooperative Association, and Scientists and Engineers for Secure Energy, has recommended the establishment of a Presidential Commission on Electric Power to try to meet this need and to facilitate the solutions to some of the problems. Such a Commission, if given an appropriate charter and membership and if it could act expeditiously, could make a valuable contribution to broader understanding of the issues in electricity as well as nuclear power and could be effective in recommending effective action.

It would be important that such a Commission not be utilized as an excuse for delaying important and urgently needed actions.

Conclusion

We believe that adequate supplies of electric power are critical to the future economic growth of the country.

We believe that the growth in demand will lead to electricity supply shortages in the early/mid-1990's unless new generating capacity is built beyond that presently existing or under construction.

The utilities should order some new units, at least in some geographic areas, within the next year or two.

New orders are only likely with new relationships between the utilities and their regulators in most areas.

Nuclear power remains an economic choice in most areas and should be considered if possible.

If nuclear power "misses out" in the first wave of new orders, it will have a more difficult time later because of the psychology and further deterioration of the supply industry.

A critical problem with nuclear power is to reform the nuclear licensing process to make it less complex, orderly and businesslike, and predictable. The evolution of standardized plants will help.

New nuclear orders are most likely to be for near duplicates of units built and operating well -- standardized plants will evolve from these. Some deferred units may be restarted and some utilities may wish to duplicate units operating on their systems.

Standardized units can be established in the procedural and operative sense by legislation but the technical judgments must be made by the NRC. Allowance must be made for site-specific requirements and the preservation of competition.

Phased approval of nuclear construction and quality assurance would be an important step which could be taken by the NRC administratively.

Pre-approval of sites is desirable for future units.

A combined construction and operating license is very important.

Constraints on backfitting are essential.

The change to an Administrator of the NRC would be helpful.

Modifications of the "source term" based on the evidence available is very important, particularly for emergency evacuation planning.

Extension of the Price-Anderson Act to provide realistic public protection is essential.

The restart of TMI-1 is a critical test of the viability of the licensing system and its credibility with the utilities.

The utilities must convey their belief in the viability of nuclear power in order to accomplish the legislative and other changes needed to make it a reality.

National leadership is essential on the part of both the utilities and the Administration. The electricity situation is critical to future economic growth and national security and deserves widespread attention even though the problems are in the future — but determined by our actions today.

The American Nuclear Energy Council and many other key organizations have endorsed the idea of a Presidential Commission on Electricity and this merits serious consideration as one way of demonstrating top-level leadership and providing independent considerations and recommendations to the public and the policy makers.

Mr. Doane. Thank you, Mr. Davis.
Mr. Randall.

STATEMENT OF DOUGLAS RANDALL, SENIOR VICE PRESIDENT, STANDARD & POOR'S CORP.

Mr. Randall. Thank you.

I'd like to direct my remarks to the areas of risk and capital productivity in the electric utility industry. These are among Standard & Poor's areas of expertise. We are not experts on utility management or regulation, we're not experts on load growth forecasting, generation resource planning, conservation or load management; and, frankly, we don't know whether there will be shortages of electricity in the 1990's or not.

We note that that puts us in the same category as most of the experts who spoke here before.

We do, however, know this. If there are shortages, it will be due at least in part to the fact that utilities across the country are neither building nor planning to build any significant additions to their baseload generating capacity. Even utilities that admit to need for additional power are planning to buy it, many from Canada and even Mexico, rather than build.

Why is that? Well, it's at least partly because utility plant has become a very bad investment in the United States today. The electric utility business is a risky business. Sales growth is no longer a given; major customers are seeking alternatives to traditional utility service, some of them through cogeneration, some by trying to make their own deals with other utilities. Costs of providing service are going up. They're going up because of fuel costs, because of regulation, because of inflated capital and construction costs. And as those costs go up, utilities find themselves in double jeopardy.

First, political regulation may be unwilling or unable to authorize rates which are sufficient to cover those rising costs.

Second, rates which are high enough to fully cover costs might price electric service beyond the ability or willingness of customers to pay.

As for utility investment, it's become a "spend at your own risk" proposition. Regulators are refusing to recognize operating plant in service on unprecedently manufactured premises. And all this translates into heightened risk for utility investors.

Now, before going on, I would like to point out that the industry financial performance in 1984 was stronger than it had been in some years due to four principal factors: first, the completion of a large number of construction projects; second, there was a rebound in sales growth which began in the middle of 1983; third, there have been substantial cash flow improvements which are thanks in no small measure to recent vintage tax benefits; fourth, retained earnings and rising stock prices have helped push capital structures higher and bring debt leverage down.

So with financial profiles looking stronger, what's the concern with risk? Well, to answer that, let's look at the factors which were underlying 1984's financial performance and see if we can't find a cloud or two to go along with those silver linings.

CONSTRUCTION

The industry may not be building much now and it certainly isn't planning to build much in the next few years, but we suspect that between load growth at whatever level, replacement of ancient capacity, and acid rain or other environnmental requirements, there may be another building boom sometime and it may come sooner, rather than later. When it does, it will be expensive, especially if spending is for counterproductive investments such as scrubbers that raise costs while reducing generating capacity and efficiency.

So while the conclusion of the current construction cycle is providing an opportunity to rebound financially, the next round of construction entails considerable uncertainty as to when it will come, what it will be for, how much it will cost and, perhaps most important, how it will be financed. Now, that's risk.

SALES GROWTH

It is true that operating leverage has turned profits or rather sales growth into substantially improved profits over the last couple of years, but it's also true that that equation runs both ways, and if sales go down as they have in the past—not frequently, but they have—profits go down a lot faster. As long as incremental costs exceed embedded costs, utilities will be faced with not only the negative impacts of cyclical demand, but also the possibility of finding themselves on the elastic portion of their demand curves, and we consider that to be a risk.

CASH FLOW

No one knows what's going to come out of the current efforts to overhaul the tax code, but Standard & Poor's is not optimistic about the future of the accelerated cost recovery and investment tax credits that have been responsible for much of the improvement in utility cash flows.

Further, if the tax writers do grant some form of offsetting relief, regulators will try to pass it on to customers, and for utilities, that's double-barreled risk.

RISING EQUITY LEVELS

Equity capital is productive only if it earns an equitable return. When regulators begin looking at equity ratios as being too high and start capping or cutting returns, that is a real disincentive to investors. It is threat, whether explicit or implicit, that investments will not be permitted to earn an equitable return. When rising equity levels have to go begging for opportunties to earn equitable utility returns, that's risk.

Now, if that's not enough risk for you, here are a few more in somewhat capsule form:

No. 1. Fuel adjustment clauses which penalize investors if fuel costs exceed forecast levels.

No. 2. Prudencey standards which require foresight to be at least as accurate as hindsight.

No. 3. Construction cost caps which deny, a priori, return on or recovery of investment without regard to future circumstances.

No. 4. Phase-in plans under which consumers not only don't have to pay for plant under construction, but also don't have to pay for plant in service.

No. 5. Inability to recover costs of abandoned projects, even though the projects might have been undertaken prudently and abandoned prudently.

No. 6. Public officials, including governors and attorneys general, who espouse bankruptcy as a viable option for electric utilities.

No. 7. Loss of load to public power and cogeneration by design of public policy.

No. 8. Avoided costs that force utilities to buy cogenerated power above the cost of alternate power and, in some cases, above the rates for which they can sell it.

No. 9. Increasing opposition to utility projects and rates by public officials with horizons only as far as the next election.

No. 10. A growing perception and, unfortunately, developing policy that when things go right, ratepayers benefit, but when they go wrong, investors take the loss.

These are areas of risk for all utilities, and for utility investors, these risks on the nonfinancial side need offsetting financial strengths as compensation. If investors are going to be asked to risk to finance the next investment in utility plant, then those investments are going to have to earn enough to attract investment capital. Unfortunately, that has not been the case.

The veritable arsenal of regulatory schemes designed to avoid or delay rate increases not only is responsible for much of the higher risk profile of today's utility industry, but also it makes it effectively impossible for utilities to earn returns on their jurisdictional investments commensurate with the risks that investors are being asked to bear.

If you do a little arithmetic with me, we'll see this. If a utility is authorized to earn, say, 15 percent on its investment, but regulators recognize only half of that investment and exclude the other half as either excess capacity or imprudent investment or due to mismanagement or some other euphemism employed to restrain rates, then the effective return on a utility investment is 7.5 percent which is slightly better than you could do on a passbook savings account.

That's the rate of return on which the utility will have to sell securities to finance its next capacity addition, not the nominal 15 percent which has been authorized by regulators.

Now, bear in mind that utility managers work for utility stockholder. It is their job to earn returns for stockholders that are competitive with the returns that are available from comparably risky investments. If they can't, then investors will not invest additional capital in the utility. Where it not possible to earn sufficient returns, regardless of why, the only logical and prudent course available to management is to refrain from investing. Since regulatory policies in an increasing number of jurisdictions make it virtually certain that utility investments will not earn the cost of capital, utility managers in increasing numbers are making the logical and prudent decision not to invest in utility plant.

I'd like to note a couple of comments made by utility regulators that appeared in a recent issue of the Wall Street Journal. One commission chairman was quoted as saying that utilities have been terribly naive in assuming that regulators were required to pass costs on to ratepayers.

Well, if that's true, what does that say about the regulators who authorize utilities to book many of these costs as assets to be recovered at a later date? From my experience on Wall Street, I know that if you sell securities based on a promise to pay and then tell bond holders they're terribly naive if they expect to get their money back, you can expect lawyers for the bond holders to use words like "fraud" and "racketeering."

And, by the way, you'll have an awfully tough time selling more bonds when you need to raise money again.

Another public utility commission chairman told the Journal that more regulators were treating utilities like other businesses and requiring investors to bear the costs of poor management decisions. He did not say that regulators would treat utilities enough like other businesses to allow investors, and not ratepayers, to reap the benefits of superior management. I suspect most regulators aren't quite ready for this kind of equanimity.

You see, there is no regulatory mechanism to provide tangible recognition or reward for superior performance. If relatively strong profits result from good management, regulation will try to reduce rates so that customers, and not investors, benefit from good management.

At the same time, less than perfect management is penalized by regulators who deny recovery of expenses and disallow utility plant investment. This places the burden for imperfect management squarely on investors by making it virtually impossible for utilities to earn anything close to their authorized returns.

Under these ground rules, let's see how utility investments stack up against investments in the other businesses that regulators say utilities should be like. Consider IBM. I don't believe everything IBM touches turns to gold. Managers there make bad decisions, and IBM makes some bad investments which have to be written off at the expense of stockholder profits. But they also make an awful lot of good investments and good decisions, and those good investments have earned enough to have produced pretax return on investor-supplied capital of more than 40 percent in both 1983 and 1984. Standard & Poor's rates IBM's long term AAA. We regard it as having a minimum of financial risk.

General Electric also has a AAA bond rating. Its pretax return on capital was about 30 percent in each of the past 2 years. G.E. isn't perfect either, but the returns on its good investments more than offset the impacts of its mistake in its bad investments.

The electric utility, on the other hand, electric utility industry, rather, earned less than 13 percent on investor-supplied capital in 1983 and again in 1984. That's hardly a return commensurate with the risks of the industry as we've been discussing them here today, especially when you compare them with 30 percent and 40 percent for G.E. and IBM in their AAA bond ratings.

However, you may say it's not fair to compare electric utilities with IBM and G.E. OK. Let's see how the industry stacks up against U.S. industry in general. The pretax return on investor-supplied capital for the companies which make up the Standard & Poor's 400 industrials index was a little less than 20 percent in 1983, and probably a little more than 20 percent in 1984. We're still compiling those figures for last year.

Now, that's a difference of 700 basis points between the return on investment for electric utilities and the return on investment for a broad cross-section of unregulated American industry. That cross-section includes companies with poor returns and losses, as well as the IBM's and the General Electrics.

Well, I ask you, is U.S. industry as a whole that much riskier than the electric utility industry? As far as Standard & Poor's is concerned, the answer is no. Then why does its return on investment carry such a heavy premium over the returns on electric utility investments? Well, some would argue that regulation has had an unduly restraining influence on the product of capital invested in electric utilities. Others would blame management. I would argue that it really doesn't matter who or what is responsible for this absence of capital productivity.

What does matter is that the increasing risk and declining productivity of capital in the industry mean that there are safer investment opportunties, yielding better returns elsewhere. In short, regulated electric utility plant is becoming a lousy capital investment for rational investors.

The implications of this should be obvious. Unless the industry is able to earn a return on its investment which is competitive with comparably risky investments outside of the utility arena, good utility management will not commit capital to invest in additional plant. They won't commit that capital because they won't be able to raise it economically in capital markets where investors, and not regulators, have the power to determine required returns.

If capital is not available to support the industry's ultimate construction needs, and if the various forecasts of slow load growth that some of us heard today are wrong, and if efforts to implement load management, encourage additional conservation or develop alternate sources of electricity fail, then some areas of the country may well have a long hot summer to look forward to one of these years.

Investors will find their returns elsewhere.

Thank you.

[The prepared statement of Mr. Randall follows:]

Increasing Risk in the Electric Utility Industry

Submitted to the
United States Senate Committee
on Energy and Natural Resources

Douglas Randall
Senior Vice President
and
Thomas D. Mockler
Vice President

Standard & Poor's Corp.
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1. Introduction

Standard & Poor's has been rating corporate bonds since 1923, municipal bonds since 1940 and commercial paper since 1969. A rating is a judgment on credit quality. It represents Standard & Poor's assessment of the likelihood of timely payment of interest and principal on specific securities. Our sole perspective is credit quality. We are not in the underwriting or investment banking business. We do not give rate case testimony. We are not in the consulting business. We don't give advice for a fee. Our sole responsibility is to fixed income investors and only to the extent that we provide them with accurate and timely ratings.

The benefits of strong credit ratings are twofold:

A. Better access to capital markets.

B. Lower cost of borrowing.

A utility with a 'AA' rating has better access to capital at reasonable rates than a utility with a 'BBB' rating, or one with a non-investment grade rating. This is very significant for the capital intensive electric utility industry which has a large appetite for external financing. A "flight to quality" caused by a market aberration, adverse economic or political developments, or a utility bankruptcy might effectively foreclose utilities with weak ratings from the capital markets.

The other side of the coin is the cost at which funds are raised. While it is true that in the current market even utilities in dire financial straits have been able to secure financing, they have paid a premium for the privilege. Public Service of New Hampshire, for example, sold 'CCC' rated debentures late in 1984 at an effective yield of more than 20%. Typically, 'AA' rated bonds will cost significantly less to sell than bonds rated 'BBB' or lower. The spread can be as wide as several hundred basis points. A difference of only a few basis points on a multi-million dollar bond offering can cost rate payers substantial amounts over the life of a 30 year bond. The precise spreads between various ratings can vary significantly at different times, depending on market circumstances.

Standard & Poor's has no interest in promoting any particular rating. We don't advocate either high or low ratings. As a matter of policy, we are indifferent as to what the ratings are as long as they are accurate. We are, however, willing to explain our rating process to any and all interested parties and to discuss our expectations of creditworthiness for different rating categories. The financial benchmarks discussed later are one example of this.

2. Increasing Business Risk

The present electric utility industry is riskier than it was 20 years ago and may become riskier still over the next 20 years. To illustrate, consider that in 1970, more than 60% of outstanding electric utility senior debt ratings were either 'AA' or 'AAA'. Today, barely one quarter of electric utilities have senior debt rated 'AA' or better. In addition, some 10% of electric utilities have senior debt rated 'BB' or lower, indicating a 'speculative' capacity to pay interest and principal. Major institutional investors, such as banks, insurance companies and pension funds, may be precluded by either regulation or sound investment policies from investing in securities with such 'speculative' or 'non-investment grade' ratings. A number of generic factors collectively make the present utility industry more risky than in prior years. These heightened risks are manifest in the economic, financial, regulatory, political and competitive areas.

Most noteworthy is that the economics of the industry have changed dramatically. Higher electricity prices attributable to rising fuel and capital costs have created substantial revenue requirements that regulators in many instances may be unwilling or unable to grant. No longer do utilities complete central station power plants and file rate decrease requests with state commissions as was customary in decades prior to the 1970s when economies of scale associated with addition of new capacity permitted a general reduction in utility rates. This has lead to the utilization of "non-traditional" ratemaking principles by regulators which can seriously detract from financial performance. [Regulatory considerations will be discussed separately in Section 3.] Additionally, higher rates, to the extent they occur, have a depressing effect on volume sales growth. In fact, a permanent loss of portions of electric load may occur, thereby forcing higher costs to be carried by an ever shrinking customer base.

Aside from the question of rate relief, higher costs associated with new plant construction frequently intensify financial stress for the utility involved. This results from the need to finance new units at much higher unit costs than operating plants providing a cash return. In many instances the lower cost operating units are unable to generate sufficient cash to prevent stressful dependence on borrowed funds to finance new construction. This phenomenon is not limited to nuclear construction. More and more we are seeing coal plants completed or projected at more than $2000 per kilowatt compared with only several hundred dollars per kilowatt in prior decades.

Competitive pressures in the industry are also becoming more pronounced. Now more than ever the erosion of the industry's so-called monopoly position is becoming increasingly evident. Cogeneration, industrial self-generation, wholesale competition, technological and lifestyle conservation as well as alternate energy production are all present day facts of life. Since competitive pressures have the potential to divert sales away from utilities, negative financial consequences may ensue. Loss of load to competition will result in a need to spread higher capital costs over a smaller customer base. To the extent this results in the need for economically or politically unfeasible rate increases, earnings and derivative financial protection measures will likely suffer.

Moreover, the lingering effects of inflation will likely remain with us for some time, despite significant recent progress in this area. As an illustration, embedded interest costs for the industry have risen from 3.6% in 1962 to 9.8% in 1984 - an increase of more than six hundred basis points. It is noteworthy that during the same period earned returns on common equity increased at a much slower pace from 10.7% to 14.5% - even including allowance for funds used during construction (AFDC), a non-cash accounting entry used to artificially inflate utilities' reported earnings. Excluding these 'fantasy profits', electric utilities earned a paltry 7.3% on their owners' investments in 1984. Thus, return on investment has failed miserably as an offset to increasing risk and greater financial stress. As a result of this disparity, the industry's pre-tax interest coverage ratio, an important measure of credit quality, has dropped from vibrant levels of more than five times to about three times. And these averages obscure the extremely frail financial condition of numerous companies engaged in major construction. In some cases interest expense is not even covered once by cash income before interest and taxes.

On the legislative front, the spectre of tax reform may well result in a substantial increase in financial risk for electric utilities. Potential loss of tax benefits such as the investment tax credit and accelerated depreciation (estimated at about $4.7 billion last year) could greatly weaken the ability of utilities to generate cash internally. This would result in ever more stressful dependence on external financing and a concomitant reduction in bondholder protection, and would impair the utilities' ability to undertake necessary capital projects to ensure service reliability. Pressure will be on regulators to pass any offsetting tax relief to ratepayers, thereby leaving utilities in worse financial shape than before passage of legislation.

3. Regulatory Response

At this point, let us examine the regulatory response to increasing risk in the electric utility industry. Recent regulatory trends involving pronounced deviation from historical ratemaking principles have interjected yet additional elements of business risk into the industry. Completion of certain plants in the years ahead may require substantial customer rate increases to reflect full returns on and recovery of capital invested. Needless to say, this can be politically and economically difficult. As a consequence, regulation has devised a veritable arsenal of schemes designed to delay or avoid large rate increases:

- "Incentive" Regulation
- Phase In
- Prudency Penalities

Whatever their social merits, these new ratemaking principles seriously impair the quality of utility assets and earnings and undermine investor confidence in jurisdictional regulation.

A. Incentive Regulation

The emerging tendency to tie cost recovery to operating efficiency is disquieting since the stability and integrity of the revenue stream are threatened. There is also a concern that targets may be set unrealistically high as a political palliative to artificially restrain rates. In the case of Arkansas Power & Light, for example, the company has historically experienced significantly lower earnings as the result of its inability to meet targeted nuclear operating levels under terms of a particularly onerous fuel adjustment provision. Other examples of this kind of operating efficiency mechanism are emerging in California and Arizona. This kind of mechanism clearly subverts earnings stability and exposes net income to considerable downward potential. This is especially true with nuclear power where special operating challenges exist. Additionally, mechanisms of this type create a conflict between nuclear safety considerations and the need to reach target operating levels to ensure expense reimbursement.

B. Phase-In

The addition of newly completed units to rate base for a full cash return will have decidedly different rate impacts in different jurisdictions. In those states where cash returns on construction work in progress (CWIP) have been denied, rate increases of up to 80% may be required for full rate treatment. As a consequence, revenue requirements, at the behest of regulatory and political authorities, are frequently spread out or "phased-in" over a period of years. However, in states like Texas, Illinois and New Jersey, a much different situation exists. Pre-operational phase-in through cash returns on significant amounts of CWIP will result in more manageable revenue requirements and lower customer rates in the long run. Additionally, ratepayers have received more accurate product price signals, thus enabling them to adjust consumption habits accordingly. There is, of course, the added benefit of healthier utilities with comparatively lower capital requirements and borrowing costs.

Utilization of a cash return on CWIP to help finance heavy capital spending has fallen into political disfavor across the nation. Legislative restrictions and prohibitions on CWIP usage have recently been imposed in Texas, Connecticut, Illinois and Pennsylvania. Many other states, such as California, have long standing prohibitions against a cash return on CWIP. As a consequence, avoidance of "rate shock" associated with completion of large projects will become increasingly difficult and will encourage future post completion phase-in of revenue requirements.

The popularity and widespread appeal of post-operational phase-in are exceeded only by the almost unshakeable popular perception that endless rate increase delays are both possible and preferable. Yet post-operational phase-in provides no panacea for either ratepayers or bondholders. Almost by definition, the future is uncertain. There is no guarantee that collection of deferred revenues at some distant future date will become a certainty. We consider the trend toward deferred revenue recovery to have very definite negative implications for credit quality.

If a deferral of rate increases stretches into the next construction cycle or a period of financial or economic trauma, utilities will experience redoubled financial stress. The combination of new rate increase requirements coupled with past rate increase deferrals could virtually force regulators to propagate a self-perpetuating phase-in pattern. For those who feel that a multi-year construction hiatus virtually eliminates the potential for future rate pressure, we would respectfully disagree. Possible fuel price escalation, environmental legislation or tax law modifications cannot be wished away. Moreover, the potential for acceleration of demand growth above forecast levels can very quickly reintroduce spending stress and the need for rate relief. Any mechanism to delay rate increases may well result in a mortgage on the future in exchange for the political expedience of near-term rate moderation.

Moreover, post-operational phase-in creates an enlargement of a unit's ultimate revenue requirement. In this context, the concept of a post completion "rate moderation plan" is euphemistically deceptive. While it is true that the initial rate shock is mitigated, installment rate relief, like installment credit, results in higher customer costs in the long run. If deferred revenues earn a return, thereby increasing the size of the asset and its eventual revenue needs are increased. It was realization of these facts that prompted the Iowa commission to reject rate moderation proposals in its 1984 decision for Iowa-Illinois Gas & Electric Co. Further, if deferred revenues do not earn a return, the utility and its investors suffer a real economic loss which cannot help but act as a disincentive to additional utility investment.

Lastly, in the case of a lengthy phase-in we need to consider not only present financial repercussions but also problematic future treatment by a succession of different regulators. There is no assurance that a future commission will not alter or abrogate previously established phase-in plans. In fact, commissions have been known to reverse decisions within very short time periods, as did the Arkansas commission in a 1985 decision to rescind its permission for Arkansas Power & Light Co. to implement a rate increase associated with coal-fired activity.

C. Prudency

The continuing proliferation of management "prudency" reviews remains a matter of serious concern for maintenance of bondholder protection. Retrospective regulatory scrutiny of utility performance with the potential for imposition of substantial financial penalties has become almost commonplace in many jurisdictions. Whether a utility is penalized because of excess capacity or construction imprudence, credit protection is undermined. And the magnitude of proposed disallowances can be substantial. The New York State Public Service Commission decided that $1.35 billion of the cost of Long Island Lighting Co.'s Shoreham plant was imprudently expended. The California Public Utilities Commission staff has recommended a $762 million disallowance of Southern California Edison and San Diego Gas & Electric's investment in the San Onofre facility. The Missouri commission has disallowed $384 million of the cost of Union Electric's Calloway plant as imprudent. Many other proceedings are still pending. Although "prudency" reviews may be advanced as sincere attempts to ensure competent management practices, they are sometimes little more than politically induced solutions to the problem of sharp rate hikes. As such, they are decidedly negative from a credit perspective and heighten generic risk for the industry.

The apparent completion of a construction project does not fully insulate even a relatively strong utility from the negative effects of "prudency" disallowances. In these instances, maintenance or improvement of bond ratings will depend upon the ability of other factors to counterbalance unsupportive ratemaking practices. The potential for enhancement of cash flow and moderation of capital spending may not, in itself, prove sufficient. Extrapolation of unpredictable or unresponsive regulatory intent into other areas causes serious concern for preservation of credit quality. State commission actions with respect to prudency issues may offer insight into probable ratemaking treatment in other matters. This is particularly true where the operation of various "incentive" mechanisms for fuel expense recovery or plant operation can induce significant earnings volatility.

4. Credit Consequences of Increasing Industry Risk

In view of the significant increase in business risk for the electric utility industry, Standard & Poor's announced in January of this year a revision of financial benchmarks used in our rating analysis of electric utility debt securities. [See Exhibit A.] When business and industry risks are rising, as they are for electric utilities, fundamental financial protection has to be strengthened if credit quality -- and ratings -- are to be maintained. The adjustments to our benchmarks were not radical by any means, and they won't result in any wholesale revisions of outstanding ratings. The new benchmarks are 'evolutionary' rather than 'revolutionary'. They represent the more conservative financial profile that S&P believes is necessary to offset the greater non-financial risks confronting utilities today.

Consider debt leverage first. We've shaved these benchmarks by several hundred basis points across the board. The most readily available response to increasing industry and business risk is a less leveraged capital structure. The days when fifty-five percent debt would support a 'AA' rating are long gone. A solid 'AA' capital structure would have debt leverage sustainable at about forty percent of capital, less than ten percent preferred stock, and common equity of fifty percent or more. By the way, for a given level of debt, higher levels of preferred stock reduce financing flexibility and translate into less solid capital structures.

Net cash flow-to-total capital is a different way of evaluating the adequacy of cash flow. The benchmarks we had published before related cash flow to construction expenditures. But, construction is not a very stable series, especially when base load generation is involved. A ratio keyed to construction is going to be volatile, and it won't adequately depict either stability or sufficiency of utility cash flow. Cash flow-to-capital should be a much stabler series -- one that doesn't vary unrealistically over the construction cycle.

Net cash flow-to-capital of ten percent -- a ten-year turnover of the investment base -- is achievable with good earnings performance, realistic depreciation, and conservative tax and accounting policies. We think that's an appropriate level of cash generation for a solid 'AA' senior debt rating. This doesn't mean that we'll be ignoring construction expenditures. Where they are heavy, we'll continue to look for sufficient cash flow to fund the program without creating undue external financing stress.

The biggest difference from our previously published benchmarks lies on the income statement. We can no longer give even nominal lip service to the allowance for funds used during construction (AFUDC) -- or any other accounting or regulatory I.O.U.s -- as a source of genuine earnings protection. As the proportion of AFUDC has shot up in recent years, our confidence in the quality of the assets created by AFUDC accruals has gone down sharply. We used to say that AFUDC was like a long term receivable. Well, we've had to change our opinion. We've reclassified that long term receivable as a bad debt.

AFUDC has come to represent more than half of industry earnings. The result is a real return on investment that is completely uncompetitive with capital market driven rates. Common dividends have to be paid out of illusory profits. This forces utilities to borrow just to maintain access to the capital markets.

Obviously, when something is as important to profits as AFUDC has become, you'd like to believe that you'll be able to realize some of it someday. Unfortunately, with the growing proliferation of phase-ins, prudency proceedings, management penalties and other mechanisms for denying recovery and returns, believing that AFUDC will turn out to be a good asset is probably wishful thinking at best. S&P is interested in assessing the protection accorded bondholders. As far as we're concerned, AFUDC doesn't provide any protection at all.

Our new electric utility financial benchmarks are a bit tougher than the old ones, that's true. But the industry is a bit riskier than it used to be. The industry's risk in 1985 isn't compatible with the 'AA' rating it enjoyed in 1970. S&P's new electric utility financial benchmarks demonstrate that utilities will need stronger financial profiles to achieve and sustain strong ratings than in the past.

5. Implications of Increasing Risk for the Next Construction Cycle

Forecasts of future electric demand growth and the timing of the next construction cycle vary considerably. This is understandable given the uncertainty associated with long range projections. Before focussing on the issue, however, it is appropriate to consider the willingness and ability of the industry to commit to a new round of stressful capital spending activity. Many utilities have indicated a decided reluctance to undertake new base load projects in view of heightened construction risks and regulatory disincentives to additional investment in utility plant. After all, utilities begin to look fairly healthy when not confronted with burdensome financial pressures, prospects for substantial prudency disallowances and the potential for lengthy phase-in of revenue requirements. Stock prices rise. Financial measures improve. Regulatory and political pressures decline. This may at least partly explain the attractiveness of diversification into less politicized, non-utility businesses.

The impending conclusion of the most stressful construction program in modern times could afford the industry a much needed respite from onerous capital spending and provide an opportunity to strengthen weakened financial measures in anticipation of the next construction cycle.

Over the near term, the industry as a whole will likely experience an interval of aggregate spending abatement. From a credit perspective, this will prove beneficial. A prolonged period of reduced financing would allow moderation of external funding stress and concurrent enhancement of credit quality. A premature renewal of construction activity would clearly diminish the extent of any potential industry recovery. The proximity and magnitude of the next construction cycle will be of critical importance to the industry's ability to restore and sustain creditor protection at satisfactory levels. And indications are that the next round of building may be challenging. The rising cost of coal fired generation, increasingly difficult site selection and consumer activism all represent formidable challenges.

Notwithstanding seemingly ample reserve margins - a revitalized national economy, increasing customer reliance on electric energy, and retirements of existing facilities will ultimately combine to absorb surplus capacity and necessitate new generation additions. The question is when. Simultaneous interaction of several external variables have the potential to accelerate renewal of onerous capital spending.

While any future forecast must be somewhat tentative by nature, a ten-year time horizon for base load additions requires a long term perspective. One somewhat plausible scenario (see Exhibit B) projects spending will drop off between 1986-1990, a number of factors could compress the five-year spending hiatus and accelerate the onset of heavy capital investment. Escalation of electric demand, environmental modifications, capacity retirements, and uncertain gas and oil availability will influence spending plans for the balance of the decade.

Let's consider some examples. First, a rash of plant cancellations and deferrals has already reduced projected 1991 generating capacity from 740gw to about 700gw. Thus, at 3% annual peak growth, nominal reserve margins would approximate 25% in 1991. However, capacity available in 1991 will still include a significant component of expensive oil and gas fired generation, displacement of which may become economically desirable or practically necessary. Potential for supply disruptions or fuel cost increases abound. About 15% of total capacity will be over 30 years old, thereby raising possible reliability concerns. Also, high nominal reserves may prove a poor indication of actual availability when adjusted for scheduled plant maintenance or forced outages.

Moreover, these reserve aggregates obscure regional situations. A reserve surplus in New York provides little consolation to a capacity-short utility in Texas. A 'Megatrends'-type migration from industrial mid-America to the West and Sunbelt could result in high regional surpluses in declining growth areas and shortages in thriving areas. Disproportionate capacity allocation could contribute to further fragmentation of a formerly monolithic utility industry. In all likelihood, many utilities will experience a respite from construction activity while others remain engaged in stressful spending programs. Our credit analysis will reflect these disparities as we view increasingly dissimilar subgroups within the same industry.

Perhaps the single most important variable for determining the characteristics of the next construction cycle will be the velocity of demand growth. Should demand increase slowly, present reserve margins of about 33% together with units currently under construction may allow deferral of stressful construction activity for a considerable time. Alternatively, should demand increase rapidly, an acceleration of scheduled construction activity may be required to ensure service reliability. Depending upon assumptions of demand growth, plant retirements and displacement of costly oil and gas fired generation, new capacity requirements by the year 2000 may vary between 9gw and 454gw (see Exhibit C). At $1,500 per kilowatt, that equates to a range between $14 billion and $681 billion. Credit implications at the respective extremes could vary between relatively benign and potentially disastrous.

One important moderating influence on rapid demand growth will be demand price elasticity. Simply put, as electricity prices rise, consumers tend to conserve, thereby reducing product demand. Between 1960-1972, demand growth averaged about 7%, reflecting in part a general reduction in prices during the period. In contrast, during the subsequent 1973-1983 time frame, demand growth slowed to about 3% annually in concert with a progressive real price rise of about 3.4% annually. While it is not possible to project future demand growth patterns with precision, it appears likely that higher prices, to the extent they occur, will continue to constrain energy use into the foreseeable future. As a result, growth at the 7% level on a sustained basis appears improbable.

Nonetheless, oversimplification of demand/price elasticity through extrapolation of past trends must be avoided. Conservation will likely restrain but not eliminate demand growth.

Several phenomena complicate application of demand elasticity concepts. Stabilization of fossil fuel costs, ultimate realization of life cycle savings on nuclear units and moderation of utility revenue requirements coincident with completion of base load capacity additions may all combine to diminish future electric price increases.

The data in Exhibit D project a rise in real electricity prices of only about 2 1/2% from 1983 through 1990. While this is but one potential scenario, the rate of electricity price increases will most likely be a lot slower than the last ten years. For example, in the absence of other base load construction, depreciation accruals and fuel savings applicable to relatively expensive nuclear plants may, over a period of years, moderate or even reduce revenue requirements, thereby stimulating electric demand. In the short term, implementation of various phase-in schemes across the country as well as the potential for a near epidemic of "prudency disallowances" will also serve to mitigate rate shock and minimize large scale consumer cut-backs. Lastly, rising prices notwithstanding, the population at large has displayed a singular reluctance to sacrifice creature comfort for cost savings when the weather becomes unpleasant.

Moreover, demand growth potential must not be viewed in a vacuum but rather as a component of total energy use. Higher electric prices may well restrain demand for that product. Nonetheless, should consumers substitute electricity for other more costly or unwieldy energy sources, strong electric gains can still occur. To illustrate, electricity currently supplies about 13% of energy consumed by end use customers compared with only 9.6% in 1973. Although electricity prices have risen in absolute terms, they have fallen relative to those of other energy forms. Thus, while electric consumption is still sensitive to cost, it is also responsive to economic substitution and differential pricing. Nor is price the sole determinant for energy source selection. Electricity is generally considered cleaner, more convenient and capable of more precise application than its competitors. As a result, the present stability of fossil fuel prices, temporary or otherwise, may not lessen the perceived attractiveness of electricity in future years.

Environmental considerations are also likely to assume a prominent role in determining the timing and severity of the next construction cycle. Enactment of acid rain legislation in response to grass roots concern for environmental purity could have a dramatic impact on industrywide capital requirements. This is all the more significant given coal's bellweather position in the industry's generating mix. Substantive legislation mandating curtailment of sulphur emissions could have far-reaching effects on capital and operating expenses, particularly if scrubber retrofits are required. Should retroactive application of scrubber technology be required for the present 184.5 million kilowatts of unscrubbed capacity, heavy capital spending and premature plant retirements would ensue. In addition to sludge disposal costs and decreased operating efficiency, capital outlays required to effect the desired environmental modifications could amount to billions of dollars. At an assumed cost of $200 per kilowatt, the capital cost to retrofit our unscrubbed coal capacity would approach $37 billion. Early retirement of older but still economic units due to environmental obsolescence could quickly deplete so-called 'surplus' capacity industrywide and hasten construction of new units at much higher embedded costs. Potential environmental costs layered upon currently lean construction projections for the next five years could intensify external financing pressure and limit opportunities for improvement of credit quality.

What then will be the chief characteristics of the next round of construction? In all probability they will vary with individual and regional needs. Cogeneration, modular construction, load management, life extension programs, and new technology will all have a place. No one resource alternative is likely to satisfy the needs of all companies. A capital minimization strategy employing aggressive load management with backup plans for purchased power or a combustion turbine may be inappropriate for a fast growing service territory. Higher fuel costs or lack of power available for purchase may result in a heavier rate relief burden over time than if construction of a central power station were initially chosen. Subsequent events might then dictate the need for a base load addition anyway, compounding the ultimate revenue requirement. On the other hand, the traditional base load strategy may prove difficult for some utilities, especially those facing high cost incremental capacity with comparatively modest rate bases.

The credit implications of the next construction cycle - whenever it occurs - are likely to be as diverse and varied as the broad range of alternatives that will confront utility management. Integration of this panorama of disparate elements into a unified strategy under conditions of uncertainty will require anticipatory, rather than reactive planning. From a credit perspective, a foundation must be laid now to provide an opportunity to approach the next construction cycle from a position of strength. This translates into thicker common equity ratios; enhanced liquidity; more substantial internal funds generation; greater flexibility, both financially and in terms of resource planning; diversified fuel mixes; retention of cash flows produced in non-construction periods so they are accessible when needed to support capital programs; and perhaps even greater involvement of political and regulatory constituencies in planning decisions. This could produce a broader popular consensus and thereby eliminate a great deal of investment risk. And without some kind of moderation of the construction and regulatory risks experienced in this construction cycle, future industry commitment of substantial financial resources during the next construction cycle may be impaired.

This brings up the question of just who is going to provide the financial resouces the industry will require to pay for the next round of construction. The answers are limited. Either investors or rate payers will foot that bill. And it won't be investors unless their investments are safe or pay an awful lot more than utility regulators are accustomed to authorizing. In view of the risks facing the industry today and the absence of returns on investment sufficient to adequately offset those risks, rate payers are likely to have to bear an increasing proportion of the construction financing burden that has traditionally been borne by investors.

A utility needs to earn on and recover its existing investments in order to provide the security and returns future investors will require. If an existing asset doesn't earn a return or even recover its investment value, investors won't supply additional capital unless they are appropriately compensated for assuming that risk. That's true regardless of why an investment may be at risk, whether it be potential plant cancellation, imprudency disallowance, mismanagement penalty, or some other political, economic or regulatory threat to capital. And it will be the market that determines the return required for a given level of risk, not rate of return experts who testify in rate cases.

Lately, the idea that investors -- and stockholders in particular -- should be forced to pay some of the costs that should otherwise be borne by rate payers has gotten a broad airing. So far, the debate has centered on things like the cost of cancelled plants, 'imprudent' investment and 'excess' capacity. But this seems bound to be a popular idea -- certainly popular enough to be extended to more traditional operating areas such as fuel and maintenance. And an uninformed consensus seems to be forming that stockholders should foot some, if not all of the bill. Unfortunately, collecting is going to be difficult because investors won't be buying.

The conventionally accepted method of 'making the stockholders pay' is by limiting the regulated revenue stream to permanently deny recovery of disallowed expenses, or return on and recovery of capital invested in cancelled or 'imprudent' or 'excess' plant. The practical effect, of course, is to reduce the return available for all capital, not just that invested in the designated disallowance.

Let's see what happens when you do that. The first thing to go would be profits retained for re-investment in the business. All capital requirements would then have to be raised externally. The next thing to go would be the common stock dividend. Slashing the common dividend effectively eliminates access to the common equity market and raises the costs of other forms of financing. Next, preference and preferred stock dividends would be eliminated. Passing these payments would close off those markets and wipe out virtually all vestiges of creditor protection. Then, if returns are cut even further so that they won't even cover interest payments, you could well wind up with a bankrupt utility on your hands.

What would be the effect of such a utility bankruptcy? First, there would be an immediate adverse effect on all utilities in the country. At least the weaker firms in the industry could find themselves foreclosed from the capital markets and face insolvency as a result. A bankruptcy could produce some near term savings for rate payers of the bankrupt utility, but those savings would be more than offset by higher capital costs for all utilities across the country. Those costs would be borne by rate payers, not investors. To be sure, investors would swallow some near term capital losses, but they would recoup them by charging more for making utility investments in the future or they would look elsewhere for more secure investment opportunities. Either way, rate payers would pick up the tab.

Now, the concept of 'sharing' utility costs isn't completely barren as long as you recognize that the sharing will be among utility rate payers. As far as Standard & Poor's is concerned, attempts to 'share' such costs with investors are bound to fail because investors cannot be forced to commit capital without the promise of compensating returns commensurate with the risks they undertake. Denying returns on and recovery of invested capital can only result in reduced returns to all capital, lower levels of confidence in timely payment of interest and preferred stock dividends, higher risk for the holders of utility fixed income securities, and, ultimately higher costs to be borne by regulated rate payers.

Exhibit A

STANDARD & POOR'S FINANCIAL BENCHMARKS FOR ELECTRIC UTILITY SECURITIES RATING ANALYSES

PUBLISHED 1/28/85

	'AAA'	'AA'	'A'	'BBB'	'BB'
Pretax Interest Coverage (Excl. AFUDC*) - X	Greater than 4.5	3.5-5.0	2.5-4.0	1.5-3.0	Less than 2.0
Net Cash Flow/ Permanent Capital - %	Greater than 10.0	7.0-11.0	5.0-8.0	2.5-6.0	Less than 3.0
Debt Leverage - %	Less than 41	39-46	44-52	50-58	Greater than 56

*Also excludes other non-cash accruals.

OBSOLETE BENCHMARKS -- SUPERCEDED 1/28/85

	'AAA'	'AA'	'A'	'BBB'
Pretax Interest Coverage (Incl. AFUDC) - X	Greater than 4.0	3.25-4.25	2.50-3.50	Less than 3.0
Net Cash Flow/ Cash Construction - %	(None Published)	Greater than 40	20-50	Less than 30
Debt Leverage - %	Less Than 45	42-47	45-55	Greater than 53

Exhibit B

Electric Utility Capital Spending

($ Billion)

1983	1985	1987	1989	1991	1993	1995	1997	1999
46.0	37.3	23.6	18.9	33.6	40.1	55.1	62.6	65.4

Includes AFDC and nuclear fuel.

Peak demand growth: 2.8% - 3% per year.

Source: "Electrical World".
September 1984, Vol. 198 Number 9.
pp. 49-56.

Exhibit C

NEW CAPACITY NEEDED BY 2000

(Gigawatts)

	Annual Demand Growth		
Existing Plant Replacement	1.5%	2.5%	3.5%
Low	9	144	303
Moderate	84	219	379
High	159	294	454

Source: Nuclear Power in an Age of Uncertainty. 1984. Office of Technology Assessment, pp. 46.

Exhibit D

COST COMPONENTS OF REAL
ELECTRICITY PRICES - TOTAL INDUSTRY

	1983	1984	1985	1986	1987	1988	1989	1990	1995
Aver. Price (¢/kwh)	6.17	6.21	6.27	6.33	6.39	6.40	6.36	6.32	6.52
Capital-%	39.7	39.7	40.2	41.0	41.5	40.7	39.2	37.5	29.5
Fuel - %	36.1	36.1	35.4	34.5	34.2	35.2	36.7	38.4	48.0
O&M - %	24.2	24.2	24.4	24.5	24.3	24.1	24.1	24.1	22.5

Source: "Annual Energy Outlook 1983"
Energy Information Administration (Published May 1984)
pp.119-144.

Mr. **Doane**. Thank you, Mr. Randall, very much.
Dr. Anderson.

STATEMENT OF DR. JOHN A. ANDERSON, EXECUTIVE DIRECTOR, ELECTRICITY CONSUMERS RESOURCE COUNCIL

Dr. **Anderson**. Thank you very much. I appreciate the opportunity from the committee to be here today. I think it's only appropriate that the one ratepayer group that is going to be represented follows the eloquent presentation by Mr. Randall about the terrible financial plight that the electric utilities have been in and appear to be in for some time.

I'd like to summarize our statement very briefly, knowing that the full statement is included in the record in its entirety.

I am John Anderson, executive director of the Electricity Consumers Resource Council. ELCON is a group of large industrial electricity consumers. Industrial electricity consumers represent approximately 40 percent of the total electricity consumption in the United States and our members represent a very sizable proportion of them, producing a wide range of products, including steel, aluminum, chemicals, industrial gases, glass, motor vehicles, textiles, and foods and food products.

Our members are extremely concerned about the future adequacy and reliability of electricity. Electricity is the life blood of American industry, and without it our members would suffer, and suffer immeasurably. Because of this, we have been extremely concerned about the great disparity between the projections put forth by many analysts as to the future adequacy and reliability of supply capabilities.

And I'd like to review very briefly with you a few of our analyses that we've done to try to reconcile the differences in these projections that we have seen. I'd like to emphasize, though, that we did not make any projections ourselves. We looked at other projections and we did not try to make any point analyses. We simply tried to test the sensitivity of the other analyses to changes in basic assumptions. Again, the underlying concern of ours was to assure ourselves at least that there would be an adequate and reliable supply of electricity.

Two years ago, we took the North American Electric Reliability Council data, NERC data—those are the utility projections, as published by the utility industry—and we observed them and said, we saw no problems, even though the utilities were saying that there were substantial problems. We said, well maybe there were some problems that were potentially there if there were certain changes that might come about.

So we took the data and put them in a computer. This is nothing very sophisticated. We simply put the numbers in a computer and we ran them out for a 10-year period by region and then we asked ourselves what would happen if various assumptions were to change. For example, if load did not grow at the rate that NERC said it was going to grow; instead, load were to grow at 1½ times what NERC said, and then at 2 times what NERC said.

If there were no nuclear plants completed after 1983, which was the date that we first did this analysis, what would happen to each region's reserve margins over the 10-year forecast? What would happen if there was an oil embargo or a coal strike—a variety of different scenarios that are explained in our testimony.

We concluded from this analysis, first, that there were no problems apparent from a capacity standpoint on either a national or a regional basis, as long as the utility projections, the utility assumptions were met.

Second, we found that the changed assumptions that we utilized impacted regions differently and there were very substantial regional differences. We concluded from that, that the problems were regional in nature, not national in nature, and that solutions therefore would have to be regional in nature. And I would like to suggest that the real problems would have to be looked at on an individual basis, a utility basis, not even regional.

Third, we concluded that threats to future electricity reliability most likely would come from fuel-related interruptions—coal strikes, nuclear shutdowns, oil embargoes, things along this line—rather than generating capacity shortages.

We noted, however, that this was substantially a different set of conclusions than many other analysts were doing. Recently, we updated this analysis, using the most recent NERC data which runs through 1994. We again tested the NERC numbers to changes in basic assumptions. Tables summarizing the results of this are included in appendix A of the prepared statement.

The findings of our analysis were very similar to those two years ago. First, we saw no reserve problems identified on either a national or a regional basis, based on the utility projections.

Second, individual regions were affected differently by different changes in assumptions.

Third, projections of future adequacy and reliability are very sensitive to changes in assumption regarding load growth. By that, we said if load were to grow at 1½ times what NERC said it would—which means nearly 4 percent per year—certain regions apparently would experience some problems, although these are just numbers, these are just reserve margins and they're fraught with errors themselves. However, it was not a disaster like we saw some predicting.

Fourth, there were some scenarios which, taken together, seemed to provide a picture that we thought helped take care of some of the potential problems. For example, a plant life extension program, repowering of planned retirements, complemented by increased cogeneration and other alternative power production, together would offset even approximately a 1½ times the load growth forecast of the NERC.

We compared the results of this research with other analyses. For example, a recent Department of Energy report published in May of this year concluded: "Bulk power in general for the period 1985–94 is projected to be adequate for meeting projected peak demands."

Furthermore, we looked at the utility numbers, the NERC numbers again, and saw that the utilities themselves are predicting a 27-percent reserve margin in 1993. We then extrapolated their load figures from 1993 to the year 2000, using load growth that they had said would occur up until then, and concluded that capacity in 1993 would exceed load in 2000, even if there were no capacity additions or subtractions between 1993 and the year 2000.

Although our research tended to indicate to us that there were not crises, at least by the early 1990's, we felt that we should look more carefully at the DOE Electricity policy project report. We analyzed it in great depth. We changed the assumptions of that report to what we considered to be reasonable set of assumptions, although probably a high level set of assumptions, and we showed that the reserve margin of the policy project report changed from a negative 15 percent to a positive 42 percent.

We concluded in our statement to DOE with this analysis, that we did not expect all of our assumptions to take place. Indeed, we said we certainly hoped that they didn't because we didn't want to see a 42-percent reserve margin in the year 2000. We also thought, though, that the negative set of assumptions from a consumer standpoint that we said DOE had assumed in that report would not be realized either, and so probably the results would be somewhere in between.

But all of this still left us somewhat confused. We were very aware that the importance of load growth on future capacity needs was of very large importance, and so we looked at the factors that we thought would influence future load growth, particularly from an industrial standpoint, but are factors.

First, many people say that we are becoming more electrified. We've heard that today, we've heard that in this set of hearings. Yes, we are becoming more electrified, but at least from the member companies of ELCON the electrification has both positive and negative results. For example, many of the things that our companies are doing and many of the things that they're being driven to do by the high prices that they are paying for electricity is to electrify, to save energy. They're putting in high efficiency motors, which results in very, very substantial savings, especially when you get into the very large motors—in hundreds of horsepower size.

They're using electronic adjustable speed drives which result in direct energy savings. Instead of cycling the motor and letting it run and consume energy when it isn't being used, you actually turn the motor off or cycle it down. They're using improved electrolysis efficiencies in the various processes that produce primarily chemicals and certain kinds of metals.

Other electrification aspects have both positive and negative impacts on electricity consumption, and we analyzed them. For example, many people say we're using robots more and more in the productive process, and robots obviously use electricity. What many people do realize, though, is that robots also save a lot of electricity.

For instance, the motor vehicle manufacturers are using robots more and more in the production of motor vehicles. However, one of their very largest electricity consumptions now, without robots, is to use electricity in the space conditioning needs. When you have humans in a plant putting together a car, you have to have the air space conditioned. When you have humans painting cars, you have to make sure that the climate and the environment is such that the human can live there safely.

When a robot goes in there, you don't need to do this anymore. So you find that the increased movement toward robotics has both very positive and negative needs on electricity.

Computers are being used in numerous applications within the industrial community. But the primary application of computers is to coordinate the productive process. It results in almost every case—well, it results in every case that I am aware of within our companies, in reduced electricity consumption.

Additionally, increased electrification may actually result in increased kilowatt consumption but decreased peak load, or at least no increases in peak load. A very important example is the movement toward electric arc furnaces in the production of steel. Electric arc furnaces use tremendous amounts of electricity to melt metal. However, they are often run only during the middle of the night. The primary or the basic melting of metal occurs between, say, 12 and 6 o'clock at night, and then the fabrication or the finishing of the metal takes place during the day.

We have taken several groups of people to Baltimore to visit a steel facility that happens to have an electric arc furnace. And in each one of the trips that we've taken up there, I at first was disappointed when the electric arc furnace wasn't working, and then I noticed the great impact that it had on people when they said, yes, Baltimore Gas & Electric made it very attractive for the steel company not to run that during the day, and run it during the night.

There are many, many examples of time and use rates and peak-load pricing kinds of things that have resulted in this type of activity.

Finally, there is much that goes on in the electrification area that motivates the industrial to cogenerate his own electricity. As more and more aspects of the process are electrified, and as rates go up for a variety of different reasons, the industrial is finding itself motivated to produce its own electricity.

Another very significant aspect, though, that will affect future electricity demand regards the recovery or the lack of recovery of the basic industries, a point that was discussed by the last panel in some depth. This is particularly true for some of the most electricity-intensive industries, such as aluminum, steel, and certain aspects of the chemical industry.

These industries are suffering from intense competition from low cost labor, capital, and energy areas. Additionally, many of these companies have already implemented significant conservation measures and, when combined together, it is very questionable whether they will ever recover to the robust levels that they used to be at sometime in the past.

Finally, rate shock, a subject that has been mentioned several times today also, is taking its toll on the industrial community. Rate shock is the sudden and severe increase in electricity prices, and it can be caused by a variety of different factors. It could be caused by sudden increases in oil prices, by a utility that has a large proportion of oil generation equipment on it, but generally today rate shock is caused by the completion of a very large and expensive construction program.

As was pointed out by several people, rate shock is, to a large extent, caused by the front-end loading of the cost recovery of the accounting systems used today in the electric utility indutry.

I must point out, though, that many times people say, well, rate shock isn't going to have its toll because the average price of electricity is falling. Well, that may be true, and it's one of the things that our members tell us all the time. It may be very true that the average price is falling, but if you happen to be on a system where a $5 billion capital investment comes on line and the cost recovery is all front-end loaded, and you have to pay the rates for the 5 years, and you're facing very intense foreign competition, you might not be around when the rates start to fall and the low end happens to come about.

Rate shock is a very substantial impact on industrial community. Rate shock highlights the idea that the demand for electricity is not perfectly inelastic. There is elasticity of demand, and it is going to have its long-term implications.

Projections of the future necessarily involve risks. The question, it seems to me is, would we rather err on the high or the low side? At least that's the way it's expressed so many times. We hear that erring on the high side, which is in my terms planning capacity needs that would meet a variety of low growth projections to make sure that we don't have shortfalls in the future, create cost impacts on consumers, though. And this is something that's often overlooked.

Many times we argue that the erring on the low side would create tremendous costs to customers because we would have brownouts or blackouts. What they forget is that erring on the high side causes cost consequences and social impacts on customers also. If erring on the high side drives basic electricity-intensive industry out of the American economy, we're not going to have jobs left in those particular industries, and there are going to be very large social consequences associated with them.

The things that our members keep telling us is that erring on the low side will not result in blackouts, and probably not even brownouts. What it will result in is what's been told today, is that we will have to meet the loads with very short construction-type generating equipment—gas turbines, for example, or small modular coal units or something along this line.

That's all not all bad, though. The price of electricity from a gas turbine today many times is much lower than the price of electricity, at least first year cost, for many of the very new expensive units that are going on line. And it doesn't make a lot of difference if the lines cross on the cost benefit 20 years from now if the customers aren't around to buy the electricity when it comes out.

Finally in our statement, we discuss somewhat the financial problems of utilities today. And our observation is that the financial problems facing utilities today is one of too much, not too little, cash. And that's, of course, not utilities; some still face real problems. But many utilities are the proverbial or, in a true sense, "cash cows" today. They have more cash than they know what to do with, and what it's doing is driving them to do things that are not good from a ratepayer standpoint.

Some of them are potential takeover targets. Some of them are diversifying into many non-utility areas. In this area, some are buying cement companies, some are buying cable TV companies, one even explored buying a professional baseball team.

The reaction of regulatory commissions to this particular situation differs, but I think it's something that we need to be very interested and very concerned about.

What is our conclusion? Our conclusion is that the lights will go out when customers decide to flip the switch. There's a lot of different reasons why they may decide to flip the switch, but the main one facing the industrials is economic—some very serious economic decisions.

What are our recommendations? Well today, at least from a Federal legislative standpoint, we do not believe that there is any need for Federal legislation. We think that we're in a grace period. We think we're in a period where we can carefully study and look at the problems or the potential problems of the industry.

But that does highlight several other things that I think we should look at very carefully. First, I think we need to improve load forecasts. And I was encouraged to hear the discussion earlier today about the different type of load forecasts. Too many times, it seems to me, we rely very heavily on macroeconomic forecasts. And I've run the black box many times myself, and I know that by changing the multitude of assumptions going in, you can get out just about any answer you want.

And I'm not saying that that's wrong. I think there's a very useful need for macroeconomic forecasts of future electricity demand. But there's another way, and it was one that was mentioned earlier. And that is, end use sector analysis in building up to the total demand by looking at individual end use sectors first—and very carefully.

I think by doing this, we can get a much better feeling as to what's going to happen in each sector. We'll get a much better feeling as to whether the commercial sector will continue to grow at whatever the percentage rate it was reported on the last panel. And I was again very pleased to hear Dr. Williams' report on his detailed analysis of the industrial demand, because I see a very low industrial load growth over the foreseeable future.

Second, I think we should study very carefully how to shorten construction time of powerplants. It's got to be one of the largest problems that we are facing today. Clearly, if we do have a problem past 1995 and it takes 10 years to build powerplants, then we better start building them today. But we know that there are alternatives.

Florida Power & Light built St. Lucy II in 6½ years and just finished it 1 or 2 years ago. That was an exception and there were some special things, but that was a large baseload nuclear unit built in the United States with the safety standards all met. Many foreign countries, as was reported, build plants regularly in very short lengths of time.

There are new modular design coal plants that are receiving a lot of attention. The idea is that they're very efficient and can be put on line very, very quickly.

If we can build efficient generating equipment in 5 years, then we don't have to start that construction for another 5 years from now, even if there is a problem in 1995 which we are not ready to conclude that there is.

There are other alternatives, as has been mentioned, nuclear licensing reform. ELCON certainly would like to see the nuclear licensing reform passed. All we're saying is that there are a variety of alternatives besides that.

Finally, we think it's extremely important that utilities be encouraged too use the existing generating equipment in more efficient ways. I would like to see the problem, quote-unquote, that many utilities have today of excess capacity, at least pockets of excess capacity turned into an opportunity. And the opportunity would be that we can share that excess capacity. We can run more efficient generating units that are presently underutilized and move the power to areas that are relying on less efficient generating equipment.

We think one way that would motivate utilities to do this would be to allow industrial customers the right to request wheeling orders from appropriate regulatory commissions. And I know this is not the appropriate forum to discuss this at great length; I simply ask that this be taken into consideration.

We feel that if industrials have the opportunity to request wheeling orders and if industrials then use this opportunity to try to find available low cost power, that what it will result in is utilities will be first in line, and go buy that power before we ever get around to doing it. But the net effect will be that all customers will benefit.

Finally, I was encouraged to hear today, and I would lke to add to that, we think that utilities should advocate enthusiastically the use of appropriate load management techniques to reduce peak demands and increase offpeak loads. Some of them are doing this, and doing it very well. But the kinds of things that we're talking about involve what has been discussed today, plus maybe some others—the installation of devices, cycle air-conditioner compressors, swimming-pool filters, hot-water heaters, things along this line.

And the expanded use of time and use rates, based, though, on the cost differences that the utility incurs. I was somewhat concerned to hear discussion earlier today about how we can just kind of sample the market, raise the price enough until something happens, and then see if that's the result you want. Time and use rates make a lot of sense if costs differ for the utility between the time periods that we're talking about.

I thank you again very much for the opportunity to be here.

[The prepared statement of Dr. Anderson follows:]

ELCON

STATEMENT OF THE ELECTRICITY CONSUMERS RESOURCE COUNCIL (ELCON) TO THE COMMITTEE ON ENERGY AND NATURAL RESOURCES UNITED STATES SENATE

ON:

WHEN WILL THE LIGHTS GO OUT?

JULY 25, 1985

I am Dr. John A. Anderson, Executive Director of the Electricity Consumers Resource Council (ELCON). I am pleased to appear before this Committee today to share with you industrial electricity consumers' views on the question:

When Will the Lights Go Out?

ELCON is a group of large industrial consumers of electricity with facilities in most of the 50 states and many foreign countries.[1] Our members produce a wide range of products including steel, aluminum, chemicals, industrial gases, glass, motor vehicles, textiles and food.

ELCON's members consume approximately ten percent of all electricity sold to industrial customers and nearly five percent of all electricity consumed in the United States. They require an adequate and reliable supply of electricity at reasonable prices. As such, they have a continuing interest in the future supply and demand of electricity.

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[1] ELCON members are: Air Products and Chemicals, Inc. • Anheuser-Busch Companies, Inc. • Armco • Bethlehem Steel Corporation • Cone Mills Corporation • Corning Glass Works • Diamond Shamrock Chemicals Company • Dow Chemical U.S.A. • E. I. du Pont de Nemours & Company • FMC Corporation • General Motors Corporation • Hercules Incorporated • Hershey Foods Corporation • Kaiser Aluminum & Chemical Corporation • Olin Corporation • PPG Industries, Inc. • A. E. Staley Manufacturing Company • Stauffer Chemical Company • Union Carbide Corporation

SUMMARY

1. For several years, ELCON has been concerned about discrepancies between forecasts regarding the adequacy of future electricity supplies. Electricity is the lifeblood of industry. Industrial firms need an adequate and reliable electricity supply -- but an adequate supply is no good if it is too expensive.

2. Two years ago, ELCON analyzed utility projections of demand and generating capabilities both on a national and regional basis. We recalculated reserve projections under alternative assumptions. We found:

   o no problems on either a national or regional basis;

   o changed assumptions affected regions differently; and

   o threats to future electricity reliability most likely would come from fuel-related interruptions (e.g., coal strikes, nuclear shutdowns, oil embargoes, etc.) rather than generating capacity shortages.

3. We recently updated this earlier research. The conclusion of the update are consistent with the earlier study. Specifically:

   o no reserve problems were identified on either a national or regional basis based on utility projections;

   o individual regions are impacted differently by changes in assumptions;

   o projections of future adequacy and reliability are very sensitive to changes in assumptions regarding load growth; and

   o plant life extension programs can provide substantial capacity assistance. However, this potential alone is not sufficient to offset unanticipated increased load growth in some regions. The research suggests that plant life extension programs, complimented by increased alternative energy resources (i.e., cogeneration development), would provide adequate reserves in most regions. Such a scenario appears quite likely given present utility and industrial plans and activities.

4. The results of our research are consistent with that of other respected analysts. For example, a Department of Energy report published in May 1985 concludes: "... bulk power in general, for the period 1985-1994, is projected to be adequate for meeting projected peak demands."

5. Furthermore, utility projections of load and generating capabilities, as reported to NERC, now show a 27 percent reserve margin in 1993 and extrapolations using their growth rates indicate that demand in 2000 would be less than generating capability in 1993.

6. Although our research indicated adequate reserves, we were concerned about quite different projections from electric utilities and the DOE policy office. To reconcile the differences, we tested the sensitivity of the DOE PPA Report to changes in assumptions.

With what we consider reasonable load growth, retirement, construction, cogeneration, and other related assumptions, the negative 15 percent reserve margin became a positive 42.9 percent figure -- a condition of excess capacity in most people's view. We do not expect (and indeed certainly hope we will not have) a 42.9 percent reserve margin in 2000 because we do not expect all of our assumptions will be realized. However, we believe it even more unlikely that all of the assumptions will turn negative from the consumer's viewpoint.

7. The importance of load growth on future electricity adequacy led us to analyze factors affecting future electricity demand. We concluded that load growth will not return to the high rates experienced in the 1960s and early 1970s for several reasons:

   o Our economy is becoming more electrified. But electrification has both positive and negative impacts on growth. The net effect of electrification may not increase electricity demands.

   o Future load will be impacted significantly by the recovery (or the lack of recovery) of basic industry -- i.e., aluminum, steel and chemicals. These industries are suffering from intense competition from low cost labor, capital and energy areas. Additionally, many companies in these industries have initiated substantial energy conservation programs which will further suppress future electricity demands. There are no real reasons why U.S. industry cannot compete internationally. However, these basic industries are highly dependent on policies that increase their electricity costs. These policies are taking their tolls. For example, electricity represents approximately one-third of the total cost of producing aluminum. Since 1981, eight percent of the domestic aluminum capacity has been permanently closed. Of the remaining, almost 25 percent is currently shutdown in favor of foreign production. Similar stories apply to steel and certain chemicals. These industries will never recover to their previously robust levels.

   o Rate shock substantially dampens future load growth -- the demand for electricity is not perfectly elastic. Rate shock is the sudden and severe increase in electricity rates. Rate shock can be caused by several factors, however it is usually caused by the completion of an expensive utility construction program. Traditional utility regulatory accounting procedures front-load cost recovery attributable to new plant additions, exacerbating rate shock problems.

8. Projections of the future necessarily involve risks. The question is, would we rather err on the high or on the low side? Erring on the high side (planning capacity adequate to meet nearly any possible situation) creates cost-impacts on consumers. These cost-impacts may be very substantial -- particularly for industrial customers facing intense competition. Such impacts may have large social consequences as industrial operations are reduced and jobs eliminated. Erring on the low side means that electricity demands may have to be satisfied with combustion turbines or other generating units with very short construction periods. We should not plan to err. However, we should recognize that electricity generated from facilities with very short construction schedules may cost less than electricity generated from some

very expensive base-load units. The "fact" that these cost differentials may change in the future (e.g., twenty or thirty years) makes no difference if consumers are no longer purchasing electricity.

9. Financial problems are not precluding most utilities from building necessary capacity. Rather, the "problem" facing many utilities today is one of too much -- not too little -- cash. Too much cash causes a variety of reactions, some not beneficial to ratepayers. Specifically, some utilities are potential take-over targets; others are diversifying into many non-utility areas; still others are increasing dividends. Regulatory commissions react differently. Some have ordered reduced rates while others have taken no action.

CONCLUSION

Lights will go out when consumers decide to flip the switch.

RECOMMENDATIONS

1. FEDERAL LEGISLATION INTENDED TO CREATE STRONG INCENTIVES TO ALLOW UTILITIES TO BUILD MORE BASE-LOAD POWER PLANTS IS NOT WARRANTED AT THIS TIME.

   o Most utilities are not planning new capacity additions at this time because such additions are not needed -- not because of financial problems.

2. AREAS THAT WARRANT ADDITIONAL STUDY -- CONGRESSIONAL OR OTHER -- INCLUDE:

   a. Improved load forecasts:

   Macroeconomic forecasting techniques are often subject to wide margins of errors. Aggregating electricity forecasts from projections of consumption by individual consuming sector may help reduce the margins of errors. Such a "get to know your customer" policy can improve forecasts while improving communication between producers and consumers.

   b. Shorten construction times:

   We must find ways to build efficient generating units when they are needed at affordable prices. Primarily this means building smaller generating units with shorter construction times.

   o A major problem in the electric utility industry today is the time required to site, license and build new base-load generating units. Long construction times increase costs dramatically and force long planning horizons.

   o Construction lead-times are increased due to many factors including: licensing and siting problems, reduced load forecasts, unanticipated construction delays, poor construction practices, etc.

- o Reduced construction lead-times would lower costs and allow utilities to build capacity as it is needed. This is far better than basing construction programs on speculative, long-term forecasts subject to wide margins or error.

There are alternatives. Nuclear licensing reform can help. Smaller coal units using conventional technologies can be built in approximately five years. And small, modular nuclear- and coal-fired units show tremendous potential and should be carefully analyzed.

c. Utilities should be encouraged to use existing generating equipment in more efficient ways:

- o Power from efficient, under-utilized generating equipment should be moved to displace generation from less efficient units. Industrial customers should have the ability to request wheeling orders from appropriate commissions. Rules should establish a rebuttable presumption that the capacity to wheel exists. These actions would encourage utilities to enter into such wheeling transactions voluntarily. Transmission systems should be improved to facilitate these transfers.
- o Utilities should advocate enthusiastically the use of appropriate load management techniques to reduce peak demands and increase off-peak loads. Examples include:
  - * installation of devices to cycle air conditioner compressors, swimming pool filters, hot water heaters, etc.
  - * time-of-use rates based on differences in costs and
  - * interruptible rates based on the cost savings to the utility.

BACKGROUND

When will the lights go out? -- The question is not new. Indeed, a fad in the seventies was to predict that shortages that would "curl your hair" would appear in just a few years. Of course, they never materialized.

Projections of the adequacy of future electricity supplies today range from one extreme to another. Some predict brownouts this summer. Others predict severe shortages in the 1990s. Still others argue that additional conservation and innovative new electricity-producing technologies will cause present excess capacity conditions to prevail throughout the foreseeable future.

ELCON has been very concerned by the discrepancies in predictions for several years. We have studied, filed statements, issued reports, written articles and given speeches before a wide range of groups and audiences on the subject.

We haven't changed our message. In fact, we are even more committed now than ever before.

What is our message?

There is no capacity limitation on a national basis that will cause severe electricity problems in either the short or long run. Lights will go out when consumers flip the switch.

We have faced, and probably will face again, localized forced outages due to inclement weather, poor maintenance, accidents, and other unexpected events. Some of these forced outages may trigger other shutdowns due to safety and technological factors.

Additionally, certain individual utilities may experience capacity problems due to poor planning, inadequate construction programs, financial limitations, or other factors. In such situations, industrial electricity consumers would support utility-specific actions to assure a continued adequate and reliable supply.

But it is disingenuous to generalize from individual, localized problems to the industry as a whole. What is needed is a careful and balanced look at the overall issue.

In this statement, ELCON sets forth our views on the capacity issue. First, we present the results of an analysis of adequacy and reliability on a regional basis. Second, we reconcile the results of this analysis with that of analysts predicting capacity shortfalls in the 1990s. We then discuss the impacts of other factors on the future supply issue. Finally, we offer recommendations.

RESULTS OF ELCON RESEARCH

Research into the future adequacy and reliability of electricity supplies necessarily is complex and imprecise for several reasons. Primarily, measures of adequacy and reliability cannot be quantified precisely or definitively. For example, the North American Electricity Reliability Council (NERC) defines adequacy and reliability in the following manner:

> Electricity adequacy:
> having sufficient generating capacity to be able at all times to meet the aggregate electric peak loads of all customers and supply all their electric energy requirements.
>
> Electricity reliability:
> the security of the interconnected transmission network and the avoidance of uncontrolled cascading tripouts which may result in widespread power outages.

Measures of adequacy and reliability differ; there is no one standard specified as the sole criterion for measuring adequacy and reliability for either an individual utility or for an integrated power system. Some of the more often used measures include: percent reserve or reserve margins, largest source of power, loss of load probability, frequency and duration criteria, and probability of energy deficiency.

For purposes of our discussion, we use regional reserve margins as proxies for adequacy and reliability. Reserve margins are defined as the amount by which installed generating capacity exceeds the annual peak demand, expressed as a percentage of that peak demand. Many analysts contend that reserve margins in the 15-20 percent range generally indicate adequate supplies of generating facilities although, as described below, each utility and situation must be examined individually before it can be determined that the particular utility will be able to provide an adequate and reliable supply of power.

We rely on regional reserve margins both because they have been relied upon recently by other respected analysts and they are easy to quantify. However, we recognize that regional reserve margins do not:

- o focus on individual utilities which actually supply power to customers (e.g., while reserves may be adequate for a region, an individual utility's reserves may be inadequate);
- o take into account the adequacy and reliability of the transmission and distribution facilities (e.g., shortages may occur even if adequate generating capacity exists and is operating);
- o account for possible changes in exogenous variables which could disproportionately impact certain utilities or regions (e.g., a coal strike or an oil embargo may create electricity shortages for utilities even though they may have large generating reserves); and
- o account for factors such as purchased power, bulk power transactions, etc. (e.g., a utility with a relatively low reserve margin but with a unit nearly completed may be in much better shape than another utility with a similar reserve margin and no construction program).

With these potential problems clearly in mind, ELCON studied future reserve margins for various regions of the U.S. under a specified set of assumptions.

We conducted this research in two parts. Two years ago, ELCON analyzed utility projections of demand and generating capabilities both on a national and regional basis. The results of this analysis were presented to DOE in the ELCON Comments on the National Energy Policy Plan IV (NEPP-IV). In this analysis, we recalculated the reserve margins projected by utilities under alternative assumptions. We found:

- o no problems on either a national or regional basis;
- o changed assumptions affected regions differently; and
- o threats to future electricity reliability most likely would come from fuel-related interruptions (e.g., coal strikes, nuclear shutdowns, oil embargoes, etc.) rather than generating capacity shortages.

Recently we updated this analysis. Data for the analysis were obtained from the NERC report titled Electric Power Supply and Demand, 1984-1993.[2] These data represent aggregations of projections developed by individual utilities in each of NERC's nine regional electric reliability councils. A map displaying the area included in each region is contained in Appendix A of this statement.

A base case was established for the United States and each of the regions. The base case utilizes the NERC's projections of peak demand growth and planned capacity additions. For reference purposes, the base case is termed Scenario (a).

The research compares the results of nine alternative hypothetical scenarios with the base case. The scenarios include:

Scenario:	Assumptions:
(a)	Base case -- Peak demand and planned capacity additions as forecasted by each NERC region.
(b)	High growth -- Peak demand grows at a rate of 1.5 times each NERC region's forecast. Capacity additions remain as forecasted by NERC.
(c)	Double growth -- Peak demand grows at a rate of 2.0 times each NERC region's forecast. Capacity additions remain as forecasted by NERC.
(d)	Nuclear moratorium -- No new nuclear units are added beyond 1985.
(e)	Coal Derating -- All coal-fired capacity derated by 10% beginning in 1985.
(f)	Alternative Energy -- Cogeneration and other alternative energy grows by 3,000 megawatts (MW) per year.
(g)	High Growth and Alternative Energy -- Assumes (b) and (f).
(h)	Double Growth and Alternative Energy -- Assumes (c) and (f).

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[2] North American Electric Reliability Council, Electric Power Supply and Demand, 1984-1993, 1984 Annual Data Summary Report (Princeton, New Jersey: 1984).

(i) Alternative Energy and No Retirements -- Assumes (f) and (l).

(j) High Growth, Alternative Energy and No Retirements -- Assumes (b), (f) and (l).

(k) Double Growth, Alternative Energy and No Retirements -- Assumes (c), (f), and (l).

(l) Repowering Planned Retirements -- Units scheduled to be retired after 1985 are repowered.

Results of the national analysis are summarized in Table 1. Appendix A to this statement contains a series of tables detailing the regional results of this research. These data suggest:

(1) On a national basis, no reserve problems are identified under any scenario incorporating NERC's growth projections. Specifically, national reserves appear adequate even under assumptions including: nuclear moratorium, coal derating, alternative energy, no retirements, and various combinations of the above.

(2) No region appears headed toward an electricity crisis by the early 1990s assuming NERC's demand and supply forecasts are realized.

(3) Projections of future adequacy and reliability of electricity supplies are very sensitive to changes in assumptions of load growth. But potential problems are localized. Specifically, three regions (ERCOT, MAPP and SPP) might experience problems if load grew at a rate 1.5 times the NERC forecast. However, this would happen only if supply assumptions were unchanged. Most regions would experience problems if load growth were to double. However, supply plans are likely to change as load grows and it is very unlikely that load will double.

(4) Neither a nuclear moratorium nor a derating of coal units significantly affects most regions. Indeed, the research suggests that only ERCOT and MAIN might experience serious problems if no nuclear units are added beyond 1985 or if coal units are derated.

(5) Cogenerators, small power producers (SPP) and alternative energy sources can provide substantial capacity assistance in regions. However, the potential is concentrated in areas with large steam loads. Thus, MAPP and SERC could experience problems if load grows at 1.5 times the NERC forecast even assuming alternative energy resources growing at 3,000 MW per year nationally.

(6) Plant life extension programs also can provide substantial capacity assistance. However, this potential alone is not sufficient to offset unanticipated increased load growth in some regions. The research suggests that plant life extension programs, complimented by increased alternative energy resources (i.e., cogeneration and SPP development), would provide adequate reserves in most regions. Such a scenario appears quite likely given present utility and industrial plans and activities.

TABLE 1

U.S. Reserve Margins Under Alternative Supply and Demand Scenarios

Scenario:	Peak Growth Rate :	Reserve Margins										
		1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993
(a) Base Case	2.26	33.3	35.1	37.3	37.4	36.9	34.6	32.8	31.2	30.5	28.3	27.2
(b) High Growth	3.40	33.3	30.5	32.3	31.3	30.0	26.6	23.8	21.1	19.3	16.1	13.8
(c) Double Growth	4.55	33.3	29.1	29.5	27.1	24.4	19.9	16.0	12.2	9.2	5.1	1.9
(d) Nuclear Moratorium	2.26	33.3	35.1	37.3	35.1	32.7	30.0	27.7	25.3	24.0	22.0	21.0
(e) Coal Derating	2.26	33.3	35.1	31.4	31.4	31.0	28.8	27.0	25.6	24.8	22.8	21.6
(f) Alternative Energy	2.26	33.3	35.1	37.8	38.2	38.1	36.2	34.8	33.5	33.1	31.3	30.4
(g) High Growth & Alternative Energy	3.40	33.3	30.5	32.8	32.1	31.1	28.2	25.6	23.3	21.6	18.7	16.7
(h) Double Growth & Alternative Energy	4.55	33.3	29.1	29.9	27.9	25.6	21.4	17.7	14.1	11.4	7.5	4.4
(i) Alternative Energy & No Retirements	2.26	33.3	35.1	38.1	38.7	38.9	37.1	35.8	34.8	34.7	33.3	32.8
(j) High Growth & Alternative Energy	3.40	33.3	30.5	33.1	32.6	31.8	29.0	26.7	24.5	23.1	20.5	18.9
(k) Double Growth & Alternative Energy	4.55	33.3	29.1	30.3	28.4	26.2	22.1	18.6	15.2	12.7	9.1	6.4
(l) No Unit Requirements	2.26	33.3	35.1	37.7	37.9	37.7	35.3	33.9	32.5	32.1	30.4	29.6

In summary, our research leads us to conclude that each region experiences different characteristics and changed assumptions impact the regions in different ways. If future electricity capacity shortfalls materialize, they must be dealt with on a case-by-case bases. Federal legislation directed at potential future capacity problems and ignoring competitive electrical cost problems for industrial consumers may not achieve the desired results and is not warranted at this time.

The results of our research are consistent with those of other respected analysts. For example, the Department of Energy recently published a report based on data submitted by utilities to NERC for the period 1985-1994.[3] This report concluded that "bulk power in general, for the period 1985-1994, is projected to be adequate for meeting projected peak demands."[4]

This DOE study projects summer peak demand growth on a national basis of 2.33 percent per annum over the 1985-1994 period. On a regional basis, DOE reports peak demand growth rates ranging from 1.15 to 3.59 percent per annum.

DOE displays projected summer reserve margins by region for the period under study. Table 2 reproduces these DOE data. They project 1994 reserve margins for all but two regions in excess of 20 percent and no region is projected to have less than 15 percent reserves. Of the two below 20 percent, MAPP borders on Canada (which wishes to sell large quantities of power to U.S. utilities), and ERCOT has a projected 1994 margin of 19.15 percent and a tremendous potential for cogeneration.

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[3] United States Department of Energy, Staff Report, Electric Power Supply and Demand for Contiguous United States, 1985-1994, DOE/IE-000311 (May 1985).

[4] Ibid., page 2.

TABLE 2

ACTUAL AND PROJECTED SUMMER AND WINTER INSTALLED RESERVE MARGINS AS REPORTED APRIL 1, 1985 BY THE REGIONAL ELECTRIC RELIABILITY COUNCILS CONTIGUOUS UNITED STATES

% RESERVE MARGIN AT TIME OF SUMMER PEAK DEMAND 1/

	ACTUAL 1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
ECAR 2/	38.24	39.05	40.28	38.00	36.94	34.81	33.77	33.21	31.11	30.41	29.08
MAAC	28.18	28.51	30.24	31.79	30.22	28.28	26.96	27.97	27.89	27.98	25.95
MAIN	20.99	29.95	28.03	34.86	35.71	33.64	31.58	29.46	27.09	25.16	23.12
MAPP 3/	38.89	31.24	29.75	27.39	27.39	24.39	21.77	19.19	16.96	14.13	13.29
NPCC 3/	33.16	29.25	31.95	35.73	33.43	31.43	29.52	28.10	25.44	25.90	23.26
SERC	39.20	33.74	33.30	34.40	32.62	33.52	30.31	30.96	28.49	27.64	25.43
SPP	32.07	36.46	37.47	33.80	30.56	26.55	23.93	24.18	22.17	22.54	21.58
SUBTOTAL 4/	34.23	33.56	34.02	34.51	33.01	31.47	29.25	28.93	26.84	26.19	24.40
ERCOT	21.75	15.35	17.95	23.74	22.15	21.31	20.75	20.52	19.66	19.73	19.15
WSCC 3/	39.42	38.40	42.95	41.58	41.65	40.09	37.61	37.00	36.19	34.14	33.25

% RESERVE MARGIN AT TIME OF WINTER PEAK DEMAND 1/

	1984-85	1985-86	1986-87	1987-88	1988-89	1989-90	1990-91	1991-92	1992-93	1993-94	1994-95
ECAR 2/	41.87	47.45	45.83	43.42	42.05	40.30	37.55	36.80	35.55	34.42	32.56
MAAC	47.29	52.86	51.59	51.56	48.06	44.31	44.51	41.38	40.32	39.59	36.91
MAIN	60.49	60.83	69.01	69.08	65.47	61.85	58.43	54.79	51.67	48.55	45.41
MAPP 3/	55.22	50.16	50.80	49.75	45.50	42.11	39.25	36.10	32.70	29.74	29.09
NPCC 3/	41.65	41.24	48.23	46.39	44.65	42.64	40.84	38.58	35.96	35.85	32.69
SERC	32.42	41.03	40.24	39.77	39.79	38.59	37.28	37.38	35.68	34.35	32.85
SPP	74.68	86.67	82.48	77.67	71.92	62.61	63.09	64.44	63.24	62.66	59.59
SUBTOTAL 4/	45.48	51.13	51.60	50.12	48.05	45.16	43.54	42.47	40.66	39.41	37.26
ERCOT	43.92	53.66	55.75	59.01	55.49	54.87	51.42	50.09	48.73	47.31	46.68
WSCC 3/	46.76	52.24	54.06	54.60	52.88	50.91	48.56	46.97	46.70	45.78	45.72

1/ % RESERVE MARGIN = $\frac{\text{NET DEPENDABLE CAPABILITY - PEAK DEMAND}}{\text{PEAK DEMAND}} \times 100$

2/ TOTAL OF BULK POWER AND LIAISON SYSTEM MEMBERS.

3/ U.S. PORTION OF COUNCIL ONLY.

4/ THIS INFORMATION IS MEANINGFUL TO SOME DEGREE, BECAUSE THE SEVEN COUNCIL AREAS ARE INTERCONNECTED. IT IS NOT HOWEVER, IMPLIED THAT THESE RESERVES CAN BE FREELY EXCHANGED AMONG ALL REGIONS OR IN ALL CASES WITHIN A REGION. WSCC HAS ONLY MINOR INTERCONNECTION CAPACITY WITH OTHER COUNCILS. ERCOT HAS A 200 MW DC TIE WITH SPP AND A 500 MW TIE IS PLANNED FOR COMPLETION IN 1989. DC TIES PERMIT ASYNCHRONOUS TRANSFERS OF POWER.

Similarly, NERC annually publishes supply and demand projections supplied to NERC by utilities. The most recent such NERC publication is for the time period 1984-1993.

Table 3 displays projections of summer peak demand and generating capability from this NERC report. These data clearly show that utilities project a 27.0 percent reserve margin in 1993. Indeed, extrapolations using their growth rates over the 1993-2000 time period indicate that demand in the year 2000 would be less than generating capability in 1993.

There will be both additions and subtractions to capacity between 1993 and 2000. Additions will involve repowering, upgrading, cogeneration, small power production and new construction, to mention a few. Furthermore, increased imports, wheeling and power pooling may effectively increase existing capabilities. Subtractions include retirements and unanticipated cancellations. Additionally, load growth is inversely related to electricity prices. The completion of new, expensive generating units and rate structures that push high industrial rates even higher would reduce load growth and the need for additional generating capacity. We believe that the additions and subtractions will significantly affect future reserve margins.

The critical question thus is: Will capacity additions exceed subtractions over the next several decades by an amount sufficient to assure a continued adequate and reliable electricity supply? We address factors impacting the answer to this question below.

TABLE 3

PROJECTED RESERVES -- NERC U.S.: NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

	Summer Peak Demand (MW)	Generating Capability, Total (MW)	Reserve Margin (%)
1983(Actual)	447,526	596,449	33.3%
1984	446,681	603,509	35.1%
1985	460,683	632,613	37.3%
1986	472,476	648,947	37.4%
1987	484,925	663,876	36.9%
1988	496,938	668,875	34.6%
1989	509,218	676,227	32.8%
1990	521,291	684,118	31.2%
1991	533,948	696,603	30.5%
1992	546,370	701,252	28.3%
1993	559,370	710,579	27.0%
	(Average Annual Growth, 1983-1993, 2.5%)		
1994	573,354	Assume: no additions or subtractions to generating capability through 2000:	23.9%
1995	587,688		20.9%
1996	602,380		18.0%
1997	617,440		15.1%
1998	632,876		12.3%
1999	648,698		9.5%
2000	664,915	710,579	6.9%
	(Extrapolated Annual Growth, 1993-2000 at 2.5%)		

SOURCE: Electric Power Supply and Demand, 1984-1993, North American Electric Reliability Council, Princeton, NJ, 1984, Table 2, page 11, and Table 8, page 23.

RECONCILING THE DIFFERENCES

Unquestionably ELCON is concerned over the widely differing views expressed by various analysts. Our goal is clear: an adequate and reliable electricity supply at reasonable prices. Our members, like all consumers, never wish to pay more than necessary. But our members recognize that they must pay their fair share of prudent and competitive utility costs. And they recognize that they would suffer immeasurably, along with all consumers, if electricity were not available either in adequate quantities or only at exorbitant rates.

Therefore, we decided to explore in detail the methodologies and underlying assumptions driving pessimistic forecasts. To do so, we focused on a report prepared by the Office of Policy, Planning and Analysis of the Department of Energy. We did so primarily because it was very comprehensive and received wide public exposure. Our analysis of this study was submitted to the Department of Energy in our August 1984 statement on the National Energy Policy Plan V (NEPP V).

The report -- The Future of Electric Power in America: Economic Supply for Economic Growth[5] -- was released in 1983. It was several years in the making. It relied on more than $2.5 million in consultants' reports as well as staff commitment. Although now two years old, we know of no updates of the report and the DOE Policy staff apparently still adhere to the conclusions.

Our critique of the PPA Report in no way should be interpreted as an inference that we believe it better or worse than other, similar reports. Indeed, in our opinion, the methodologies and assumptions incorporated by the PPA Report are quite similar to those incorporated by many other analysts.

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[5] United States Department of Energy, Office of Policy, Planning and Analysis, The Future of Electric Power in America: Economic Supply for Economic Growth, Report of the Electricity Policy Project, herein referred to as the PPA Report, Report DOE/PE-0045 (Washington, D.C.: 1983).

Rather, we focus on this report to highlight the sensitivity of projections to changes in assumptions. We offer a summary of our analysis in the paragraphs below.

The PPA Report predicted peak load growth of at least three percent per year throughout this century.[6] Total peak demand thus will be 750 gigawatts (GW) in the year 2000.

Utilities will need approximately 900 GW of capacity to meet this demand with a "necessary" (20 percent) reserve margin, according to the PPA Report. This means that utilities must be motivated to build 270 GW of capacity, above and beyond that presently planned or under construction once retirements, old-age deratings, and "uneconomic" capacity are taken into account. This prediction is summarized in Table 4.

Our analysis shows that many of the assumptions used in the PPA Report, while certainly plausible, were at the negative end of the continuum from a consumers viewpoint. Briefly:

- Load growth -- The PPA Report assumed that peak load would grow at three percent annually. It might. However, utility load growth forecasts now are less than 2.5 percent and have fallen every year since 1974. Indeed, utilities now project (as reported by DOE) peak load growth of 2.33 percent per year through 1994. Figure 1 provides data illustrating this fact. Two years ago we suggested a more reasonable alternative might be 2.5 percent per year. We still view this as a more reasonable figure.

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[6] Ibid., page 3-56.

TABLE 4

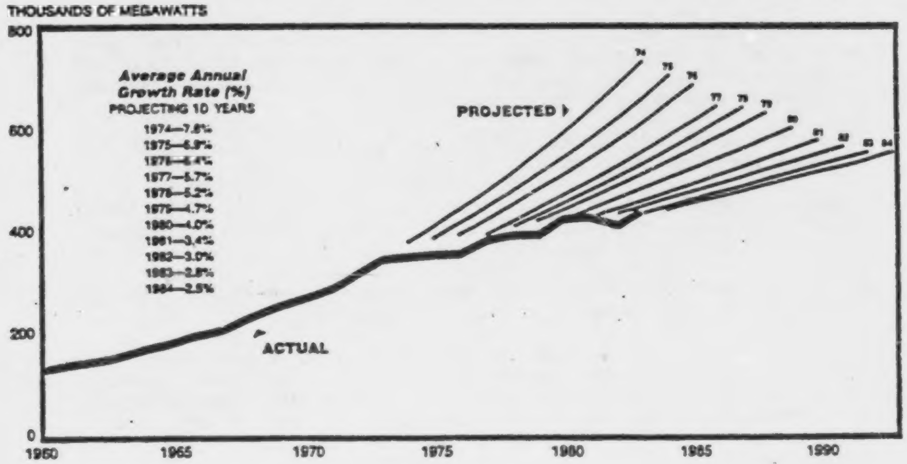
The PPA Report's Projection of the Electric Utility Industry in the Year 2000

	PPA REPORT
Projected Demand	751.0 (@ 3% growth)
Capacity in 1981:	572.2
Less:	
Retirements	50.0
Cumulative Aging	20.9
Uneconomic Capacity	38.0
Plus:	
Planned Additions:	
1981-1991	168.3
1991-2000	0
Additions Due to:	
Cogeneration	0
Wheeling, Power Pooling and Import	0
Expected Capacity in 2000:	631.6
Reserve Margin:	-15.9%

FROM: ELCON's Statement to the DOE regarding the National Energy Policy Plan V (NEPP-V), August 31, 1984, page 13.

FIGURE 1

NERC Summer Peak Demand Projections
Comparison of Annual Ten-Year Forecasts, U.S.



FROM: North America Electric Reliability Council, Electric Power Supply and Demand, 1984-1993, Published 1984, page 5.

- Retirements & deratings due to cumulative aging -- The PPA Report predicts the loss of more than 70 GW of capacity due to retirements and cumulative aging. We found it instructive that Mr. Paul Ziemer (President and CEO of Wisconsin Public Service and then President of the Edison Electric Institute) was quoted just before the PPA Report was issued as saying:

  > Repowering existing facilities would become a significant trend ... Generally, the goals of the plant-modernization projects are to extend the life of a plant another 20 to 30 years. With new fossil capacity costing $1,000 to $1,500/KW, many companies are investigating spending a few hundred dollars per KW (estimates are in the $200 to $500 range) to extend plant life and to upgrade and improve performance.[7]

  ELCON did some checking and found that many utilities were investigating power plant life extension programs. The results of this check are summarized in the article "Utilities Find Plant Life Extension Compatible with Routine Maintenance,"[8] copy is attached.

  Certainly some capacity will be retired. We assert that it will be less than 70 GW by the year 2000.

- Uneconomic capacity -- The PPA Report predicts the loss of 38 GW of capacity due to oil prices rising to $42 per barrel in 2000 (in 1982 prices). Oil prices might rise. However, we are -- and have been -- in an oil glut. OPEC has had a profound impact on our economy. But the problem now facing OPEC is how can they keep the price from falling (see the attached article "Saudis Aim to Increase Oil Output"[9]).

  Even if oil prices rise, we question whether it is in the consumer's best interest to retire otherwise operable oil-fired units. Specifically, electricity produced from expensive new generating units is equivalent to backing out very expensive oil. Indeed, in some cases it is the cost equivalent to backing out oil at more than $100 per barrel. This does not make good business sense.

  Furthermore, we said that some analysts argue that we must reduce our dependence on imported oil for reasons such as national defense and

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[7] "The Emphasis is on Diversity -- Interview with New EEI Chairman Paul Ziemer," Electrical World (May 1984) page 28.

[8] "Utilities Find Plant Life Extension Compatible with Routine Maintenance," ELCON Report, Number 28 (Second Quarter 1985) page 4.

[9] "Saudis Aim To Increase Oil Output," The Washington Post (July 7, 1985) page 1.

Longer Life, Reduced Costs Are Goals

Utilities Find Plant Life Extension Compatible with Routine Maintenance

Utilities investigating power plant life extension programs are discovering that the intensive inspections and maintenance required to keep generating units running longer than usual can be accomplished within a schedule of routine outages.

At the same time, the programs are expected to defer millions of dollars in expenditures for new generating units.

ELCON Report talked with engineers at utilities that have embarked on extended life and repowering programs.

Potomac Electric Power Company launched its Plant Life Upgrade Strategy (PLUS) in 1982 after doing a feasibility study of life extension with the help of major vendors of generating equipment. Results of the study showed that PEPCO could expect to add 30 years to the life of a typical power generating unit. Lifetimes much longer than that are theoretically possible, according to Robert Carelock, project manager.

Carelock says that PEPCO's maintenance work is done during routine outages that last 30 days when they are minor and eight weeks when they involve major work. He says the utility has not discovered any servicing needs that cannot be handled during routine outages.

Over a 10-year period, PLUS is expected to allow PEPCO to defer about $635 million in new capital expenditures while costing about $135 million for upkeep of existing equipment — for a net savings of $500 million, Carelock says.

$750-$1,000/kW Savings

Another utility, Pennsylvania Power & Light, launched its Fossil Plant Extended Life Program in 1982 after estimating that the program could save its customers half the cost of a new generating unit — or about $750 to $1,000 per kilowatt.

Under the program, PP&L spends about $1 million per year inspecting its fossil fueled plants for wear and tear. By 1987, the utility expects to complete the first five-year cycle in what it sees as a continuing program of inspections of all its fossil fueled plants. At the end of the first cycle, PP&L expects to be able to calculate the total cost savings of the program. Inspections to date indicate where some $50 million in replacement parts and equipment could be necessary over the coming years.

Tom Yezerski, manager of the program, lists reasons why life extension is a sound business decision:

- It defers the expense of having to site a new plant and the difficulty of meeting ambiguous and evolving regulations;
- It reduces costs of construction and capital; and
- Technology has not improved significantly enough to make existing plants obsolete. In fact, Yezerski says, the technology behind most of PP&L's fossil fueled plants is about as efficient as what one would expect from a brand new plant.

Nuclear Life Extension

Duke Power has begun investigating the usefulness of life extension for three of its nuclear power plants, none of which is more than 10 years old. Andy Thompson, a spokesperson for the utility, describes the program as a kind of extended life preview.

While the generating units in question are relatively new, the inspections are designed to point up possible future replacement costs. And, at the same time the power plant inspections are being conducted, Duke Power is also examining existing maintenance records to help determine which equipment wears out most quickly.

"We feel it's prudent to look at a plant before it gets too close to the end of its life expectancy," Thompson says. "In the last couple of years we've begun to look more closely at extended life."

Like Carelock, Thompson says these inspections take place during routine unit outages.

Although life extension is still experimental in many respects, it appears to be one of the important tools available to an electric utility for coping with peak load — and ultimately with load growth. As Yezerski of PP&L notes, "It's much easier to keep a plant running through extended life than to site and build new capacity, as long as electric load growth patterns don't change dramatically on a generating system." E

THE WASHINGTON POST SUNDAY, JULY 7, 1985, Page A1

Saudis Aim To Increase Oil Output

Kingdom Reported Demanding OPEC Adopt New Quotas

By William Drozdiak
Washington Post Foreign Service

VIENNA, July 6—Saudi Arabia, confronting a severe budget crisis caused by plunging oil revenues, is demanding that its OPEC partners accept a new quota system that would enable Riyadh to begin producing more oil as soon as possible.

According to well-placed delegates, the ultimatum by the world's richest oil producer was presented today by Saudi Oil Minister Ahmed Zaki Yamani, who told fellow ministers at a critical meeting of the 13-nation Organization of Petroleum Exporting Countries that the desert kingdom no longer could accept its role as the "swing producer" that adjusts its output to support prices fixed by the cartel.

Saudi oil output has dwindled to a 20-year low of 2.3 million barrels a day, less than that of Britain, in an attempt to shore up sliding prices in a world of surplus oil. But the drastic cuts have failed to prop up the market, and the Saudis now want to assume a fixed production quota along with other OPEC members.

OPEC prices are pegged to the official $28 a barrel benchmark price for Saudi light crude.

In recent weeks Yamani and King Fahd have indicated that Saudi Arabia is prepared to raise its production as much as 2 million barrels a day unless cooperation is forthcoming from other OPEC members. Some analysts predict that such a move in an era of surplus oil could drive prices as low as $20 a barrel.

The Saudis favor a "floating" level of OPEC production, which would fall during the northern summer, when fuel oil sales taper off, and rise during winter or periods of peak consumption. Because of Saudi restraint, OPEC is now pumping only 14.5 million barrels a day, well below its self-imposed ceiling of 16 million barrels. The "floating" quota plan would link the cartel more firmly with market forces, the conference sources said.

Earlier, the ministers discussed creating a new central body that would "control the marketing" of OPEC oil, according to the ministerial conference chairman, Indonesian Oil Minister Subroto. By coordinating the sale of OPEC oil, the new agency would, in theory, monitor prices and production and thus make it more difficult for members to "cheat" by making hidden discounts or barter arrangements.

But Saudi Arabia, among other members, expressed skepticism about such an agency because it would take too long to organize and inevitably would face problems about national sovereignty over oil supplies.

Following an afternoon session, Subroto said the ministers decided to set aside the establishment of a marketing body as a long-term project. When they resume discussions Sunday, the ministers will "seek some immediate measures to defend OPEC prices and its share of the market," Subroto said.

Alluding to the recent history of members who have undercut prices or churned out oil surpassing their individual quotas, Subroto said, "We have begun to discuss practices that are weakening the market." But he indicated that OPEC was no nearer to solving its problems when he said the ministers "were asked to come with suggestions about what to do in the short term to defend our prices" when they reconvene Sunday morning.

Once more, the focus of attention at the OPEC meetings has centered on Saudi Arabia's Yamani, who has warned recently that his country cannot go on for much longer at such low levels of oil production when other OPEC members are undermining the cartel's strategy.

Some analysts contend that Yamani is maneuvering the cartel toward a reduced price structure, more attuned to slack world demand, by letting pressure build on his colleagues and spreading the message that Saudi oil production will rise soon no matter what the others do.

Yamani skipped the morning session today, saying he was ill. But many observers perceived his absence as a diplomatic rebuff to those who wanted to talk about the new marketing agency as a cure for OPEC's woes.

In the afternoon, the Saudi minister guided discussion about the "floating ceiling" concept, which would tailor OPEC oil outputs to the needs of the market. The notion seemed compatible with the arguments of those members who believe OPEC's only recourse is to slash oil output even more to soak up the glut on the market.

Representatives from Libya and Algeria, who have objected vigorously to Yamani's previous hints about possible price cuts, have been the leading advocates of a steep decline in production. But several hard-pressed OPEC members such as Nigeria, Venezuela and Indonesia insist that they cannot trim back any more because they would risk default on massive debts.

In the absence of any consensus about what to do to bolster sagging oil prices, the OPEC ministers have refrained from declaring their gathering a "formal session" in which they would make decisions and instead have characterized their two days of talks here as "consultations."

The OPEC members clearly are troubled by the prospects that inconclusive results at their weekend meeting here will send negative signals to the market when it reopens Monday and probably lead to a further erosion in oil prices.

Some delegates have hinted that the consultations may be called off by Monday, with a formal conference to be scheduled again later this month to give OPEC members more time to figure out ways to regain control of the slumping oil market. Such a decision would be consistent with the cartel's pattern of muddling through its crises in the hope that world economic recovery will yield an upturn in oil demand.

The ministers appear to have avoided any consideration so far of a general price cut that would bring OPEC rates more in line with prices on the free or "spot" market, where as much as 80 percent of the world's oil is now changing hands at prices $2 to $4 below OPEC levels.

balance of payments.[10] Indeed, at one time even the DOE seemed to adhere to such a philosophy. Specifically, DOE stated:

> As a matter of economic health and national security, we *must* reduce our reliance on imported oil and achieve a more *balanced* and mixed resource base ...
>
> *Every* action we take to reduce our dependence on oil -- *particularly* imported oil -- is clearly in the national interest."[11]

Reasonable people may differ regarding the need for certain policies for national security reasons. However, electricity consumers clearly are harmed when new generating facilities -- unneeded for capacity reasons -- significantly increase electricity rates. This is particularly true for much of our industrial base which is fighting to stay in business and preserve American jobs under a barrage of foreign competition.

Consumers need electricity. However, they do not need billions and billions of dollars added to their electricity bills for benefits that, at best, are "justified" for national defense reasons. Hence, in our alternative calculations we assumed no loss of capacity for uneconomic reasons.

- *Planned Utility Additions* -- A key assertion of the *PPA Report* is that *utilities will add no new* capacity between 1991 and 2000. We consider this assertion incorrect for several reasons. Primarily, utilities are not now planning new capacity additions beyond those already approved -- and they shouldn't. They aren't needed. Additionally, utilities have an obligation to serve and regulatory commissions have an obligation to regulate in a manner that assures an adequate and reliable electric supply at reasonable prices. We have confidence that utilities and commissions will make every attempt to meet their responsibilities.

  In the alternative we set forth last year we calculated capacity additions as though they increased at a rate between 1991-2000 identical to that projected by utilities for the 1982-1991 period.

  This probably was high. Indeed, it could be viewed as an upper bound. However, the *PPA Report* assumption of zero additions between 1991-2000 clearly is too low.

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[10] See for example: Henry M. Schuler, "Risks of War and Economic Dependence, Is Conflict More Acceptable Than Developing Supplies Here?," *Los Angeles Times* (May 25, 1984).

[11] Prepared statement of United States Secretary of Energy, Donald P. Hodel, at the hearing on the recertification of the Grand Gulf 2 nuclear power plant, before the Public Service Commission of Mississippi (Jackson, Mississippi: July 10, 1984) page 3 (emphasis in original).

- Cogeneration -- The PPA Report projections assume zero capacity additions due to cogeneration because "most of (the) cogeneration would likely be consumed by the industries producing it."[12]

This is simply incorrect. Increased industrial cogeneration capacity reduces the need for additional utility capacity.

Last year we said that we agreed with another arm of DOE which expects between 40 GW and 55 GW of cogeneration by 2000.[13] This was based primarily on our knowledge of industrial firms and large cogeneration technology.

Since that time, we have been impressed with the attention directed toward cogeneration by commercial firms. To cite two:

> McDonald's is testing a prototype 65 KW cogeneration at several locations. The small-scale, natural gas fired system provides most of the electricity, heating and cooling needs of 3,000 square foot restaurants. Electricity is generated and waste heat recovered to provide hot water and, with absorption chillers, cooling. The same waste heat provides the minimal heating needs.[14]
>
> A car wash and service station in Aurora, Illinois, recently installed a General Motors, 350 cubic inch, V-8, truck engine and a 50 KW generator to meet nearly all of its hot water and half of its electricity needs. They expect to save nearly $10,000 per year with this installation.[15]

We know that there is a substantial potential for industrial cogeneration -- some of which operates more efficiently and reliably than many conventional utility generating facilities.

Commercial cogeneration increases, perhaps substantially, this potential. An assumption of zero for capital additions attributable to cogeneration clearly is negative from a consumer's standpoint. Indeed, we may find that our earlier 40 GW to 55 GW is too low.

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[12] PPA Report, op. cit., page 4-33.

[13] "Are Utilities Obsolete? A Troubled System Faces Radical Change," Business Week (May 21, 1984) page 119.

[14] "McDonald's Eyes More Cogen. Due to Pilot Job," Energy Users News (January 14, 1985) page 2.

[15] "Car Wash Uses Truck Engine for 50-KW Cogen.," Energy Users News (May 20, 1985) page 5.

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ENERGY USER NEWS, MONDAY, JANUARY 14, 1985

McDonald's Eyes More Cogen. Due to Pilot Job

OAK BROOK, Ill.—A prototype installation of a 65-kilowatt cogeneration system at a McDonald's early last spring is operating successfully, and may mean a second installation at one of the world's largest restaurant chain's San Diego locations, according to Doug Horton, staff director, system development at McDonald's Corp.'s headquarters here.

The small-scale, natural gas-fired cogeneration system was designed and engineered by Intellicon Inc., San Diego. (See April 2, 1984, EUN page 1.) Installed in Chula Vista, Calif., the system provides most of the 3,000-square-foot restaurant's electricity, as well as heating and cooling through its waste heat recovery system.

While Horton stressed that the system's performance is still under evaluation, he suggested that McDonald's may invest in a second small-scale system for an all-electric restaurant in the San Diego area, where the regulatory and economic climate is favorable. Such an installation would probably be undertaken later this year.

Although Horton declined to reveal actual savings figures, he said they are in line with original projections of a 26 to 40 percent reduction in the price they previously paid for electricity. These savings should still displace roughly $27,500 to $30,000 annually of natural gas needed to fire the system.

EUN FOLLOW-UP

The waste heat recovered from the engine's cooling loop and exhaust system is used to create chilled water through two, 10-ton hot water absorption chillers for cooling, according to sources at Intellicon. The water is heated to 195 degrees F. The same waste heat recovery system supplies the facility's minimal heating needs, they added.

Horton noted that the cogeneration system should pay for itself in about four years—the same payback period originally projected by McDonald's. However, he added that there is potential for an improved payback because of electric rate increases from San Diego Gas & Electric (SDG&E) as well as possible gas decreases, as the utility filed for a 9 percent decrease last fall.

Since the system has been installed, an "unexpected delightful surprise" has occurred, according to Horton. He said that because of the restaurant's buy-back arrangement with SDG&E, some of the excess electricity sold to the utility carries the restaurant's 10.8 cents per kilowatt hour (kwh) purchase price instead of the utility's buy-back rate of 6.7 cents per kwh.

Horton explained that the utility combines the two meters—the one that tallies incoming power from the grid and the one that measures outgoing power to the utility—together over the entire month before determining whether the restaurant is a net buyer or a net seller of electricity for that month.

If the restaurant ends up being a net buyer of electricity for the month, then the kwh sold to the utility are subtracted from the kwh bought from the utility and tallied at the 10.8 cents per kwh rate. This means that all of theelectricity sold during that month has the net effect of being worth 10.8 cents per kwh, he said.

While this unexpected savings would seem to shorten payback on the system, the restaurant did not meet projected cooling savings from the waste heat recovery system over last summer, offsetting the effect of unexpected savings, Horton explained.

Although he declined to say how much less attractive the savings were, he noted that the problem occurred because the controller needed to be fine-tuned. The waste heat recovery system has since been optimized.

While the system has experienced a few intermittent days of downtime, Horton said that it runs more than 95 percent of the time it is supposed to function. He explained that the problems stemmed from the failure of electrically-operated valves and faulty piping. Fully operated by an Intellicon controller, the system runs approximately 18 to 20 hours daily, and is shut down during the middle of the night. There have been no major problems with the controller, Horton added.

A major aspect of McDonald's thrust in investing in cogeneration was that the system require no assistance from unskilled restaurant employees in order to operate. "The 'hands off' requirement for the store manager is an unqualified success, due to the Intellicon control system," Horton observed, adding that overall, McDonald's is quite satisfied with the investment.

—Laura Gardner

cogeneration

Car Wash Uses Truck Engine for 50-kw Cogen.

ENERGY USER NEWS, MONDAY, MAY 28, [illegible] Page 5

AURORA, Ill.—A car wash and service station here expects to cut its electricity costs by nearly $10,000 a year with a 50-kilowatt (kw) cogeneration system driven by a truck engine converted to burn natural gas.

The system, which was installed at Paul and Bill's Standard Auto Wash in January, is expected to meet nearly all of the facility's hot water requirements and generate roughly half of its total electricity needs, according to Bill Rudigier, the station's owner. Hot water is used for both space heating and car wash operations, Rudigier noted.

The cogeneration system is owned by Energy Conservation Systems, also located in Aurora, and leased to the car wash for $275 a month. Under the lease agreement, Rudigier is committed to rent the system for three years, after which he can buy it at fair market value, renew the lease or have ECS remove it for free.

According to John Barr, ECS president, the system consists of a 350 cubic inch, V-8 truck engine, manufactured by General Motors Corp., capable of generating 120 horsepower; a 50-kw generator manufactured by Marathon Electric Corp., Wausau, Wisc.; and a stainless steel heat exchanger fabricated by ECS. It would have cost Rudigier $26,000 to purchase, he said. The system was installed by local electrical and plumbing contractors at a cost to ECS of about $2,000, he added.

In addition to the monthly lease payments, the service station will be billed by ECS for all power generated by the unit at a rate of 1.5 cents per kilowatt-hour (kwh), Rudigier explained. The station is currently paying its local utility, Northern Illinois Gas Co., 9.8 cents per kwh, he noted.

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Natural gas costs for the unit are estimated to be slightly more than $12,000, roughly identical to what the station had paid to heat water with its existing gas-fired boiler, Rudigier said. Under the agreement, Rudigier will be responsible for all routine maintenance required by the unit, including maintaining its supply of natural gas.

Though little actual operating information was available, projections offered by ECS and confirmed by Rudigier estimated that the cogeneration system should provide the station with electricity that would have cost $18,900 a year if purchased from the utility.

The car wash will pay $6,320 annually to ECS for generating electricity, Barr said. With the $3,300 in total yearly lease payments, the net annual savings are estimated at $9,320, he added.

According to Rudigier, these savings will come mostly during the 7-month heating season, when the system will operate an average of 500 hours a month. Savings during these months will be about $1,255 per month, or about $8,785 in avoided power costs, according to Barr.

Because of reduced heating requirements during the five summer months, the unit is expected to run at only 60 percent of the rate it runs during the heating season, said Barr. Monthly savings in electricity are expected to be $753 during this period, for a 5-month total of $3,765, he added.

Actual savings during the summer period, however, could be much lower or not materialize at all, since Rudigier said he has not yet determined whether it will prove to be economical to operate the system primarily for electrical generation.

Additional savings from the system will be gained by the sale of excess electricity to the utility, generated during the evening when the station is closed. At this time the system runs intermittently, at a rate sufficient to maintain minimum heating requirements, also generating unneeded electricity, said Barr.

Rudigier and Barr have yet to conclude negotiations with Northern Illinois, but expect to receive a buyback rate of just under 5 cents per kwh during non-peak hours. All revenues gained by the sale of power to the utility will be credited against the station's purchased electricity costs, Barr explained.

The cogeneration system has an overall combustion efficiency of roughly 90 percent, with a rated fuel input of 600,000 Btu per hour. By recovering heat from both the engine cooling jacket and exhaust, the system is capable of generating 450,000 Btu per hour, Barr said.

Heat generated by the cogeneration system is passed through the unit's heat exchanger and transferred to water stored in the station's existing 800,000 Btu per hour gas boiler, Barr said. The system can generate a sufficient amount of heat to raise water temperature to approximately 180 degrees F., he explained.

In all but the coldest weather, the cogeneration system alone will provide enough hot water for both the car wash and for space heating without the need for supplemental firing by the existing boiler, Barr added.

Should the system be unable to keep up with the demand for hot water, the burners of the boiler will turn on automatically, he said.

The cogeneration system will be activated based on the demand for hot water, so that if heating and car washing requirements fall, the system will shut down if sufficient amounts of hot water are present, he noted.

- Wheeling, Power Pooling and Imports -- Wheeling, power pooling and increased imports have the potential to reduce utilities' needs for additional capacity. Yet the PPA Report assumed zero capacity additions attributable to these potentials.

  We recognize that it is difficult to estimate precisely the magnitude of future benefits attributable to wheeling, pooling and imports. Indeed, until the capabilities and potential problems of each are clearly understood, we believe that the potential should not be considered substantial. However, we believe that assigning a zero value to these potentials suggests yet another negative from the consumer's viewpoint.

In summary, our reconciliation leads us to conclude that those predicting a crisis regarding future electricity supplies have not made their case. Table 5 emphasizes this point.

The right hand column indicates the sensitivity of the PPA projection to changes in key assumptions. With what we consider more realistic load growth, retirement, construction and cogeneration assumptions, PPA's negative reserve margin becomes a positive 42.9 percent figure -- a condition of excess capacity in most people's view.

All of the assumptions underlying the figures in the right hand column probably will not be realized -- two and one half percent load growth, minimal retirements, steady capacity additions, and continued active cogeneration development throughout the remainder of this century. Thus, we probably will not have (indeed, we certainly hope that we will not have) a 42.9 percent reserve margin in the year 2000. However, it is even more unlikely that all of these factors will be negative from the consumer's viewpoint. Thus, we do not envision a -15.9 percent reserve margin in 2000 either.

TABLE 5

The Effect of Changes in Certain Key Assumptions on the PPA Report's Projection of the Electric Utility Industry in the Year 2000

	PPA REPORT	Possible Alternative
Projected Demand	751.0 (@ 3% growth)	687.5 (@ 2½% growth)
Capacity in 1981:	572.2	572.2
Less:		
Retirements	50.0	10.0
Cumulative Aging	20.9	0
Uneconomic Capacity	38.0	0
Plus:		
Planned Additions:		
1981-1991	168.3	168.3
1991-2000	0	197.0
Additions Due to:		
Cogeneration	0	45.0
Wheeling, Power Pooling and Imports	0	20.0
Expected Capacity in 2000:	631.6	982.5
Reserve Margin:	-15.9%	+42.9

FACTORS AFFECTING FUTURE ELECTRICITY DEMAND

Projections of potential future electricity supply problems are highly dependent on projections of future electricity demands. Indeed, our research suggests few problems if load grows at rates equal to or below that projected by utilities today. However, problems may appear in certain regions if load growth increases.

Electricity demand grew at a seven percent per annum during the 1960s. Some analysts now allege that electricity demand either is growing or will grow at rates greatly exceeding those now forecast for several reasons. Some of the more often mentioned are discussed below.

Short-term vs. long-term comparisons:

Some analysts assert that recent large percentage increases in electricity consumption compared with year-earlier data indicate basic changes in electricity growth rates. Such assertions are incomplete, primarily because they confuse energy consumption and peak load growth.

Increased electricity consumption often does not require additional capacity. Utilities can generate many more kilowatt hours (KWH) from existing capacity by running the generating equipment more hours each year. It is increased peak load that requires additional capacity. Increased KWH consumption often simply means that the summer hot spell or the winter cold spell was longer one year than in the past.

Electrification:

Some analysts assert that future electric demand will grow rapidly due to increased electrification.

ELCON has looked at the electrification potential and its impact on load growth in some detail. The speech attached to this statement outlines the results of this preliminary investigation.

We conclude that there will be further electrification throughout the economy. However the electrification may not add to peak growth for several reasons.

First, electrification has both positive and negative impacts on load growth. Electrification in certain industrial processes will increase total electricity consumption. To the extent that they occur in the United States, increased use of electric arc furnaces in steel production or electric furnaces in glass melting, expanded use of electric resistance and induction furnaces for heat treating, and other such movements toward electricity-driven technologies will tend to increase electricity consumption.

However, other electrification applications have been shown to result in decreased electricity consumption. For example:

> High efficiency motors result in a direct, often significant, reduction in consumption.
>
> Electronic adjustable speed drives also result in direct electricity savings.
>
> Improved electrolysis efficiencies allow the same amount of product to be made with less electricity.

Some of the most dramatic developments in electrification may cut two ways, adding to, while at the same time reducing or controlling electricity demand. Two examples illustrate this paradox.

> Robots are being used increasingly in motor vehicle manufacturing. Certainly they will use electricity. A point often overlooked, however, is that a primary electricity use in motor vehicle manufacturing is for space conditioning. Robots do not need air conditioned work spaces. Thus, the increase in electricity consumption attributable to the operation of the robot is at least partially offset by reduced use due to changes in space conditioning. It is too early to tell which impact will be larger.
>
> Computers are being used in numerous industrial applications. Operating these devices certainly requires electricity and may require air conditioning. However, the computer applications of which I am aware nearly always result in net electricity savings by cutting down wasted, useless and lost energy.

Second, increased electrification may result in increased energy sales but not peak load growth. Electrification may increase offpeak consumption or may involve manufacturing processes that can be interrupted. Many electric arc furnaces are operated during the night. The steel is then reheated for processing during the day. Additionally, operators of arc furnaces may be willing to have service interrupted if offered an appropriate economic incentive, even when the interruption results in a increase in the number of KWH used per ton of output. Similar situations exist in many other primary metal and chemical operations where opportunities for electric-intensive innovations appear great. All customers of a utility may benefit where electrification results in increased KWH consumption without increases in peak load.

Finally, increased electrification coupled with changing conditions in the electric utility industry motivates self- and cogeneration of significant portions of new load.

At the turn of the century, industry generated nearly 60 percent of the nation's electricity. By 1980, industrial generation represented less than three percent of all generation.

However, changing economic conditions once again are making self- and cogeneration more attractive. For example:

- Electricity produced from generating units costing $4,000/KW may cost consumers in excess of 15 cents/KWH.
- Traditional utility accounting methods "front-load" cost recovery from customers.
- Regulatory bodies often approve rates that require industrial customers to pay a disproportionately large share of the total costs of the utility.

Industrial (as well as other) electricity consumers are reacting to these and other pressures by carefully reevaluating the economics of self- and cogeneration.

Indeed, it now seems likely that industrial cogeneration capacity alone will be in excess of 50 GW by the year 2000. These facilities may range from large, coal-fired facilities to small gas-fired turbines. To the extent that industry generates the electricity used for increased electrification, utility sales will not increase and, indeed, may decrease.

Economic Recovery of Basic Industry:

Many analysts base their projections of future load growth on the assumption that basic industry in the U.S. will recover to its previous, robust levels. This is very questionable.

The aluminum, steel and chemical industries (all very electricity intensive) presently are suffering from intense competition from low cost labor, capital and energy areas. There are no real reasons why the United States industry cannot compete internationally. However, these industries are highly dependent on policies that increase their electricity costs. These policies are taking their tolls. for example, since 1981 eight percent of the domestic aluminum capacity has been permanently closed. Of the remaining capacity, almost 25 percent currently is shutdown in favor of foreign production.

The important questions are not: How rapidly will the steel industry move to electric arc furnaces? What steps are aluminum companies taking to conserve?

Rather, the more basic questions ask: Will steel be produced in Pennsylvania, Ohio or elsewhere in the United States, or in Germany and Japan? Will aluminum be produced in West Virginia, Louisiana and the Pacific Northwest or in Canada, Europe, Africa or South America? The answer lies, in large part, in the present and future cost of electricity. Therefore, future electricity load growth projections are significantly affected by assumptions regarding the economic viability of certain electricity-intensive, basic industries.

Rate shock:

Closely related to the recovery of basic industry is the problem of "rate shock." Rate shock is the sudden and severe increase in electric rates. Rate shock can substantially dampen load growth.

Rate shock can be caused by many factors such as: dramatic increases in the price of fuel or federal or state legislation requiring immediate and substantial expenditures by utilities. However, rate shock usually is caused by the completion of an expensive utility construction program.

A major problem in the electric utility industry today is the time required to site, license and build new base-load generating units. Long construction times increase costs dramatically and force planning horizons with substantial margins of error. Construction lead times are increased due to many factors including: licensing and siting problems, reduced load forecasts, unanticipated construction delays, poor construction practices, etc.

There are alternatives. For example, 300-400 MW conventional technology coal units often can be built in approximately five year periods. Additionally, technological innovations in small modular coal-fired units show tremendous potential in the very near term. The attached Electric Utility Week article provides information about one such technology.

But it doesn't have to take as long as it presently does to build even nuclear generating units. Nuclear units of designs and safety requirements similar to those in the U.S. are routinely built in five to six years in foreign countries. Specifically:

- o The Electric Power Research Institute (EPRI) states that "In Japan, France and Sweden ... ... nuclear plants can be built in approximately 60 months."[16]

- o France put eight 957 megawatt (MW) PWR units into commercial service in 1981 alone.[17] Construction periods for these units ranged from 58 months to 78 months.

- o A 950 mw BWR unit was recently built for the Taiwan Power Company in 61½ months. This unit met all U.S. nuclear licensing requirements, and all design changes recommended by the equipment manufacturer were included.[18]

Furthermore, some U.S. utilities are able to build nuclear generating units in reasonable time periods. For example, Florida Power and Light Company built its St. Lucie II nuclear unit in approximately 6½ years. The plant began operation in 1983.

The importance of shortening construction periods should not be under emphasized because electricity from expensive new generating units often is uneconomic. Indeed, oil prices would have to rise to more than $100 per barrel before the cost of electricity from existing oil-fired generators equals the cost of electricity from some new, very expensive generating units. Electricity consumers would rather buy electricity produced from oil purchased at $29 per barrel (or less) than electricity produced from units at the equivalent of $100 per barrel.

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[16] Electric Power Research Institute, An Analysis of Power Plant Construction Lead Times, Volume I: Analysis and Results, EPRI EA-288 (February 1983) page 2-16.

[17] Nucleonics Week (November 12, 1981) page 5. Nucleonics Week reports construction times for the following Electricite de France units: Fessenheim-1, 78 months; Bugey-1, 77 months; Tricastin-3, 68 months; Tricastin-4, 66 months; and St. Laurent-des-Eaux-B1, 58 months. PWR stands for pressurized water reactor.

[18] Engineering News Record (May 26, 1983) page 27. Engineering News Record reports that Taiwan Power's Kuosheng-3 had fuel loaded 61½ months after the first concrete was poured. BWR stands for boiling water reactor.

ELECTRIC
UTILITY
WEEK
McGraw-Hill
An exclusive report on the electric utility industry

April 29, 1983

EQUIPMENT & SERVICES

STEARNS CATALYTIC BEGINS MARKET PUSH FOR 300-MW MODULAR COAL-FIRED PLANTS

Stearns Catalytic, the Denver-based architectural and engineering firm, has become the first company to market a design for a small, modular coal-fired generating plant, launching its campaign in the past two weeks through presentations to member utilities of the Edison Electric Institute and the trade press.

Construction of small economic plants of about 300 MW in capacity is seen by Stearns as dealing with utility concerns over uncertain future load growth and the threat of penalties by state regulators for poor planning decisions leading to problems like excess capacity. In addition, they said cost savings of 20%, and a reduction in construction time of 40%, are possible by relying on preassembled modules rather than on-site labor.

Several utility construction and engineering managers, who heard Stearns Catalytic outline its ideas to an EEI meeting earlier this month, said the concept of modular construction deserved close attention. But none admitted to currently considering anything along these lines.

"I believe the concept is one which all those involved in the generating plant construction business are investigating very carefully," Alabama Power manager of construction, craft labor and safety Albert Malone told *Electric Utility Week*. "The potential is quite obvious," he said, taking note of reduced on-site construction, "possibly an enhanced productivity factor owing to shop construction," and labor-related savings.

Utah Power & Light manager of power plant engineering Milton Ransom agreed that the industry should "take a good hard look" at modular construction, adding that Stearns' presentation to a gathering of the EEI Construction Committee's subcommittee on advanced construction technology seemed generally well received. But "the group they were talking to would be expected to give them a sympathetic hearing," he noted. "The operating folks might look on this with a more jaundiced eye."

Detroit Edison general superintendent of construction Bernard Smith echoed that concern. "The operating people like to hang their own bells and whistles on a plant. They tend to want to modify any design," he told *Electric Utility Week*.

Stearns Catalytic has no customers yet for a modular plant, but expects to get its first order by around 1986 with construction beginning in 1987, said Lawrence Newhart, vice president, power division. The company has made a "major commitment" to the modular approach following a one-year in-house study, he said. He would not reveal the amount of money or manpower devoted to that effort.

Newhart explained that no new technology is involved in applying the modular concept, emphasizing that the concept itself has been used frequently in the past. He cited his company's own experience, which includes building a crude oil production facility that was barged to Alaska's North Slope. That facility required 200 modules compared to the 35 prefabricated units needed to be trucked for a 300-MW pulverized coal plant.

The unit would be built on one level, using a horizontal "backbone approach" in which "we have taken equipment or systems which are conventionally located next to each other and grouped them together in a module," according to Stearns Catalytic. "For example, plant air compressors, tanks, dryers, piping and controls are mounted on a single module." The company cited these advantages of modular systems:

- Shorter lead times—Construction time would be cut from 64 months, the industry average for a conventional plant, to 40 months. This allows more reliable planning and a significant savings in interest and escalation costs. "Twenty to 30% of the cost of a plant is the effect of time," said Newhart. A company study comparing a $1,750/kW conventional plant in service in 1989 with the backbone modular plant with its shorter construction schedule showed a $92.7-million savings in interest and escalation costs. This assumes 11% interest and a 4% escalation factor.
- 20% reduction of field construction manhours—"Labor efficiency at the preassembly yard (controlled climate and crews etc.) would range from 20% to 40% better than at the construction site (depending on craft/element). Further, "improved quality control can be accomplished with detailed shop assembly and checkout procedures." The reduced site labor force should improve efficiency there by 8 to 10%, the company claims. On-site time is also reduced because "with adequate spacing between modules, and between equipment on modules, operating and maintenance access is improved," compared to conventional, multi-level plants.
- Greater planning flexibility—The smaller size plants require less capital commitment and allow utilities to better match new plant with load growth, lessening the threat of overbuilding and regulatory penalties. The shorter lead times also allow utilities to delay construction decisions for an extra year. Newhart said a 3,000-MW to 5,000-MW utility system experiencing 2% to 3% annual load growth would require a 300-MW plant every three to five years.

"Utilities have to stop thinking in terms of economy of scale," said George Preston, director of the fossil fuel power plant department of the Electric Power Research Institute. EPRI is concentrating most of its research efforts in modular construction in pressurized-fluidized-bed-combustion technology. Despite economies of scale, Preston said a 300-MW PFBC unit could be built at the same cost per kW as a 500-MW pulverized coal unit due to the savings from modular construction.

EPRI has committed a "quite minimal" amount of $500,000 for the next five years to study construction management improvements for fossil plants, said Preston, while about $10-million is being spent for PFBC research. ASEA Stal will be building a PFBC plant for American Electric Power if AEP obtains a grant from the Dept. of Energy (EUW, 22 April, 10).

Preston said he knew of no other architectural/engineering firms besides Stearns Catalytic that are marketing modular systems.

The use of traditional electric utility regulatory accounting procedures exacerbates rate shock problems. Under traditional regulatory procedures for new utility plant additions, the full value of the investment is placed into rate base for cost recovery from ratepayers when the facility begins commercial operation. The full value includes actual installation cost plus capitalized cost. The asset's capital cost is then depreciated on a straight-line basis over its remaining life, and customers are billed for depreciation expense and a return on the undepreciated portion of investment. As the asset is depreciated, customers' fixed cost obligations decrease. Thus, traditional electric utility accounting procedures "front load" cost recovery. Figure 2 illustrates the impact of traditional accounting methods on revenue requirements of a utility.

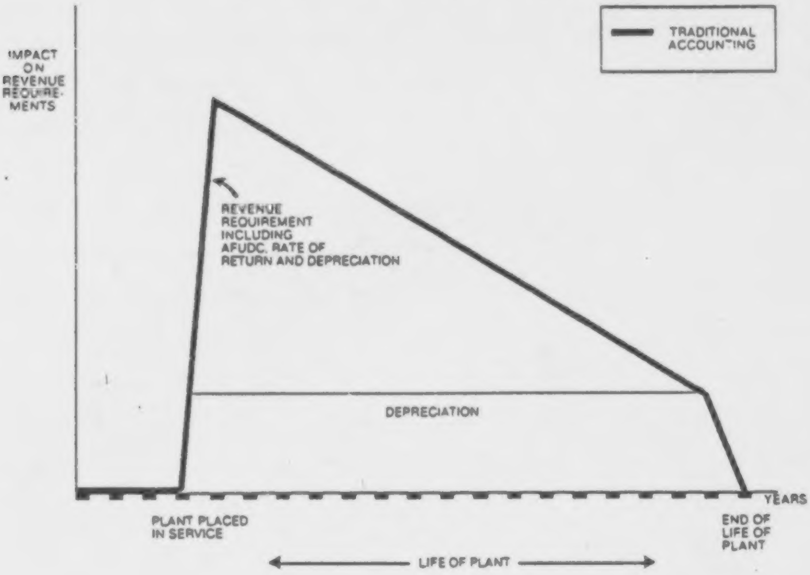
This traditional accounting method is acceptable when the rate impact is mild. A small impact on customer bills was typical in an environment where the cost of new facilities approximated the cost of existing facilities or when load growth was sufficient to permit a growing rate base to mitigate the impact of a large, one-time addition.

When the addition of an asset substantially increases the size of rate base, traditional accounting methods often create rate increases that are unacceptable both financially and politically. Fortunately, there are alternatives.

In rate cases where "rate shock" is an issue, utilities, commissions and ratepayers alike have proposed a concept which tends to levelize the rate impact of new plant additions. This concept is known as "phase-in." Typically, the adoption of a phase-in proposal results in a gradual increase in rates over a specified period of time in lieu of an immediate large increase. Phase-in of a new plant addition changes the timing of cost recovery employed by traditional accounting methods. Appropriate phase-in proposals attempt to balance ratepayer impact with the financial needs of the utility.

FIGURE 2

A Representation of Impact on Revenue Requirement of Rate Base Treatment of a New Generating Plant Using Traditional Accounting Methods



Phase-in also has been employed in instances where a public utility commission (PUC) has determined that a major plant addition resulted in capacity that was in excess of system requirements (including an adequate margin). In a number of these cases, PUCs determined that some portion of the utility's investment be phased-in to rate base as it became "used and useful" in providing service.

Several different phase-in methods have been ordered by state public utility commissions. Figures 3 and 4 illustrate four such methods. The appropriateness of each particular method depends on many factors and must be determined on a case-by-case basis.

In summary, several factors are restraining the rate of growth of electricity demand. We believe that these factors combined will restrain future growth to levels significantly below the levels experienced in the 1960s.

RISKS ASSOCIATED WITH PROJECTIONS

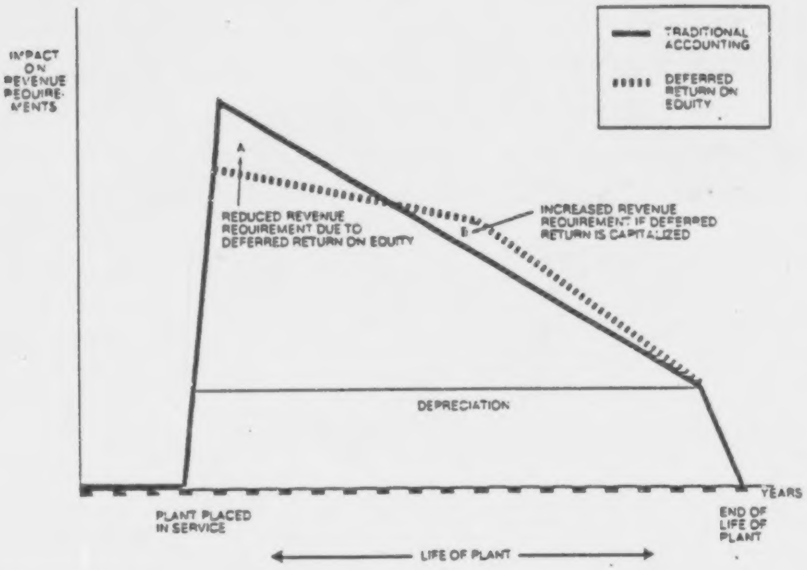
Construction programs designed to meet overly optimistic demand growth projections means under-utilized base-load generating equipment and higher prices. Alternatively, construction programs designed to meet low demand growth projections means load must be met with generating equipment with short construction periods.

Projections of the future necessarily involve risks. The question is, would we rather err on the high or on the low side? Erring on the high side (planning capacity adequate to meet nearly any possible situation) creates cost-impacts on consumers. These cost-impacts may be very substantial -- particularly for industrial customers facing intensive competition. Such impacts may have large social consequences as industrial operations are reduced and jobs eliminated. Erring on the low side means that electricity demands may have to be satisfied with combustion turbines or other generating units with very short construction periods. We should not plan to err. However, we should recognize that electricity generated from facilities with very short construction schedules may cost less than electricity generated from some very expensive base-load units. The "fact" that these cost differentials may change in the future (e.g., twenty or thirty years) makes no difference if consumers are no longer purchasing electricity.

FIGURE 3

ALTERNATIVE #1

A Representation of Impact on Revenue Requirements Due to Deferred Return on Equity for a New Generating Plant



ALTERNATIVE #2

A Representation of Impact on Revenue Requirements Due to Modified Depreciation on a New Generating Plant

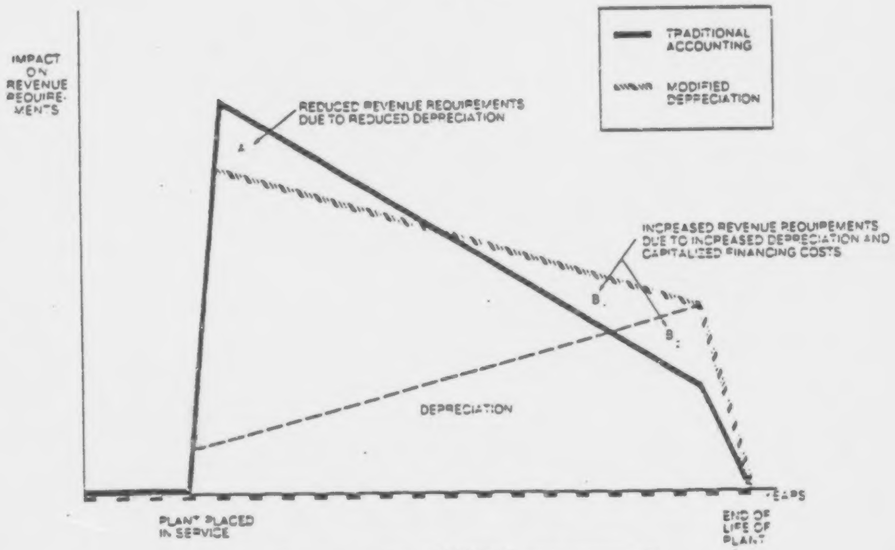
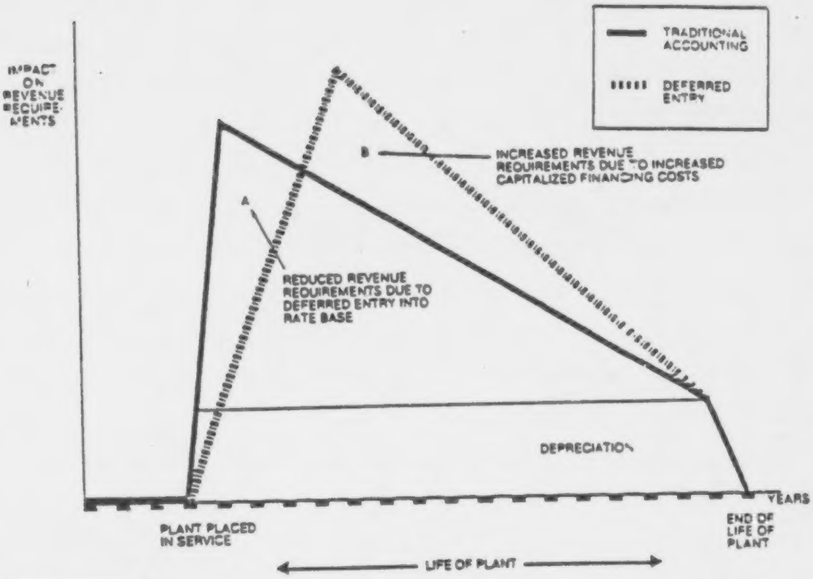


FIGURE 4

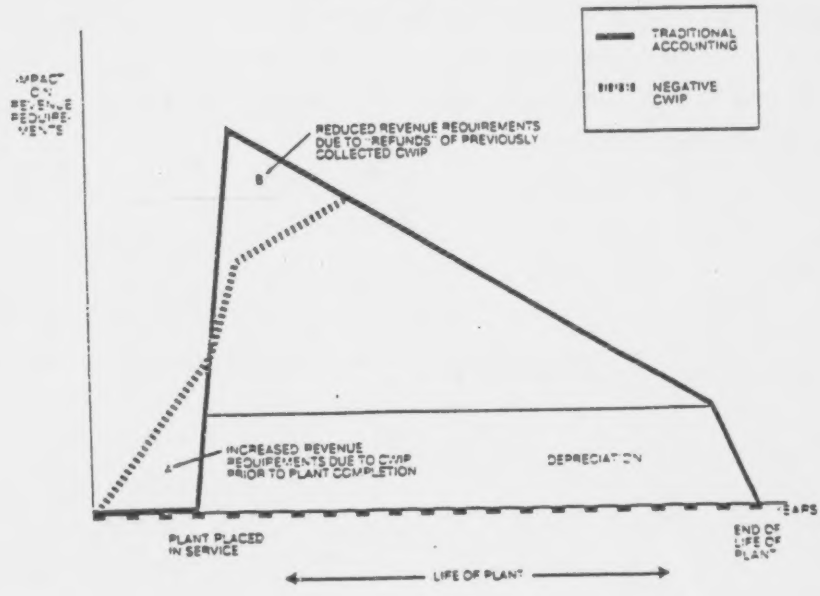
ALTERNATIVE #3

A Representation of Impact on Revenue Requirement Due to Deferred Entry of a New Generating Plant into Rate Base



ALTERNATIVE #4

A Representation of Impact on Revenue Requirement Due to Negative CWIP Provisions for a New Generating Plant



CURRENT FINANCIAL HEALTH OF ELECTRIC UTILITIES

Utilities argued that financial constraints precluded them from building "necessary" new capacity. Several years ago many utilities were experiencing severe financial problems. Today, however, some of the same utilities have become "cash cows" in the classic sense of the term.

According to Forbes, the "problem" is that many utilities are completing their construction programs and not starting new projects.[19] As completed units go into rate base, previously non-cash earning imputed to construction programs are replaced with cash earnings and cash outflows are reduced significantly.

Inappropriate rate structure also can create excessive cash. Specifically, a utility over collects when KWH sales exceed those forecast and fixed costs are collected in the energy component of the rates.

Forbes identified 17 utilities expected to generate large amounts of cash in 1986. Table 6 reproduces the financial data reported by Forbes on these utilities.

Similarly, Electric Utility Week recently reported that the realized rate of return exceeded the allowed rate of return for 35 utilities in their latest rate case.[20] Table 7 displays the Electric Utility Week data. These data show that the rate of return earned by some utilities exceeded their allowed rate of return by more than four percentage points. Furthermore, the utilities actual return earned by four utilities in 1984 exceeded 20 percent!

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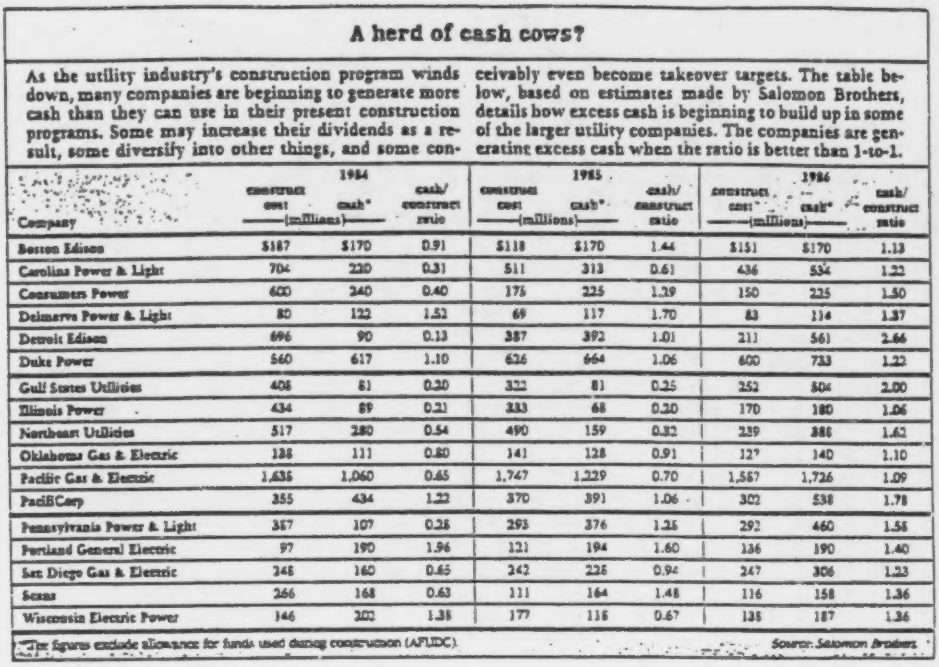
[19] "Many Happy Returns," Forbes (January 28, 1985) page 30.

[20] "35 Utilities Exceed Allowed Return; Regulation Reaction Varies Widely," Electric Utility Week (April 1, 1985) page 1.

TABLE 6



A herd of cash cows?

As the utility industry's construction program winds down, many companies are beginning to generate more cash than they can use in their present construction programs. Some may increase their dividends as a result, some diversify into other things, and some conceivably even become takeover targets. The table below, based on estimates made by Salomon Brothers, details how excess cash is beginning to build up in some of the larger utility companies. The companies are generating excess cash when the ratio is better than 1-to-1.

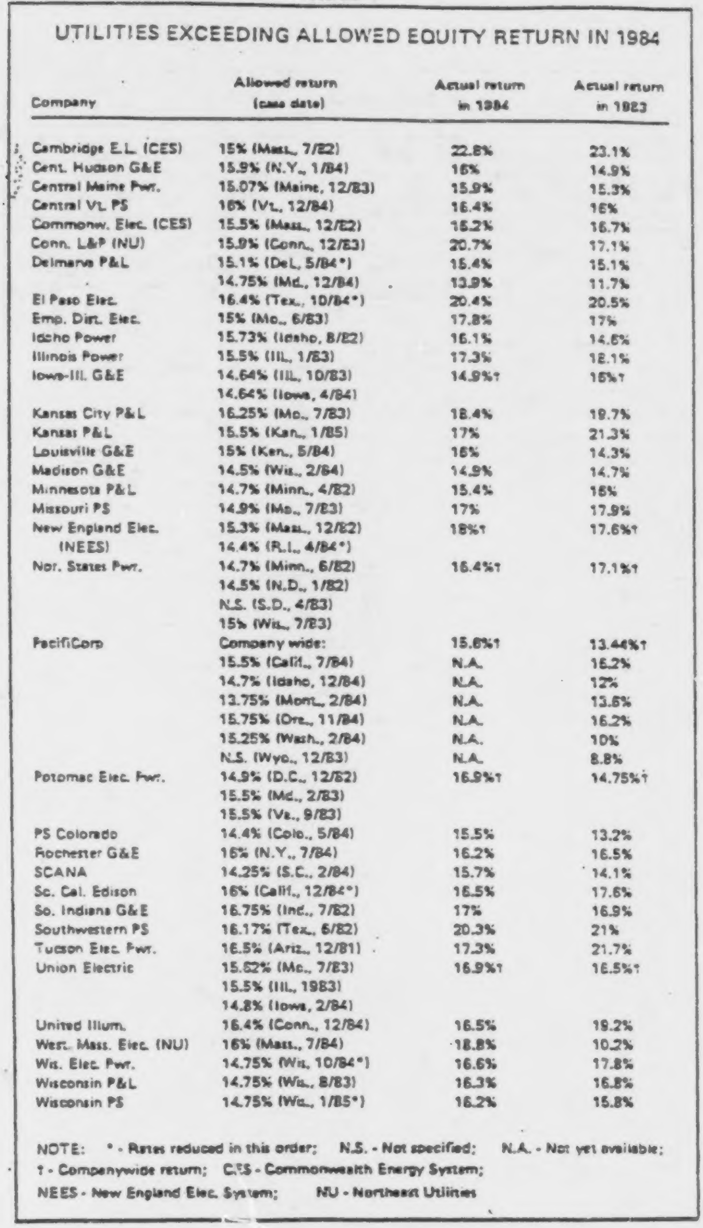
	1984			1985			1986		
Company	construct cost (millions)	cash* (millions)	cash/ construct ratio	construct cost (millions)	cash* (millions)	cash/ construct ratio	construct cost (millions)	cash* (millions)	cash/ construct ratio
Boston Edison	$187	$170	0.91	$118	$170	1.44	$151	$170	1.13
Carolina Power & Light	704	220	0.31	511	313	0.61	436	534	1.22
Consumers Power	600	240	0.40	175	225	1.29	150	225	1.50
Delmarva Power & Light	80	122	1.52	69	117	1.70	83	114	1.37
Detroit Edison	696	90	0.13	387	392	1.01	211	561	2.66
Duke Power	560	617	1.10	626	664	1.06	600	733	1.22
Gulf States Utilities	408	81	0.20	322	81	0.25	252	504	2.00
Illinois Power	434	89	0.21	333	68	0.20	170	180	1.06
Northeast Utilities	517	280	0.54	490	159	0.32	239	388	1.62
Oklahoma Gas & Electric	138	111	0.80	141	128	0.91	127	140	1.10
Pacific Gas & Electric	1,636	1,060	0.65	1,747	1,229	0.70	1,587	1,726	1.09
PacifiCorp	355	434	1.22	370	391	1.06	302	538	1.78
Pennsylvania Power & Light	357	107	0.28	293	376	1.28	292	460	1.58
Portland General Electric	97	190	1.96	121	194	1.60	136	190	1.40
San Diego Gas & Electric	248	160	0.65	242	228	0.94	247	306	1.23
Scana	266	168	0.63	111	164	1.48	116	158	1.36
Wisconsin Electric Power	146	202	1.38	177	118	0.67	138	187	1.36

*The figures exclude allowance for funds used during construction (AFUDC).

Source: Salomon Brothers

SOURCE: "Many Happy Returns," Forbes, January 28, 1985, page 30.

TABLE 7



UTILITIES EXCEEDING ALLOWED EQUITY RETURN IN 1984

Company	Allowed return (case date)	Actual return in 1984	Actual return in 1983
Cambridge E.L. (CES)	15% (Mass., 7/82)	22.8%	23.1%
Cent. Hudson G&E	15.9% (N.Y., 1/84)	16%	14.9%
Central Maine Pwr.	15.07% (Maine, 12/83)	15.9%	15.3%
Central Vt. PS	16% (Vt., 12/84)	16.4%	16%
Commonw. Elec. (CES)	15.5% (Mass., 12/82)	16.2%	16.7%
Conn. L&P (NU)	15.9% (Conn., 12/83)	20.7%	17.1%
Delmarva P&L	15.1% (Del., 5/84*)	15.4%	15.1%
	14.75% (Md., 12/84)	13.9%	11.7%
El Paso Elec.	16.4% (Tex., 10/84*)	20.4%	20.5%
Emp. Dist. Elec.	15% (Mo., 6/83)	17.8%	17%
Idaho Power	15.73% (Idaho, 8/82)	16.1%	14.6%
Illinois Power	15.5% (Ill., 1/83)	17.3%	18.1%
Iowa-Ill. G&E	14.64% (Ill., 10/83)	14.9%†	16%†
	14.64% (Iowa, 4/84)		
Kansas City P&L	16.25% (Mo., 7/83)	18.4%	19.7%
Kansas P&L	15.5% (Kan., 1/85)	17%	21.3%
Louisville G&E	15% (Ken., 5/84)	16%	14.3%
Madison G&E	14.5% (Wis., 2/84)	14.9%	14.7%
Minnesota P&L	14.7% (Minn., 4/82)	15.4%	16%
Missouri PS	14.9% (Mo., 7/83)	17%	17.9%
New England Elec. (NEES)	15.3% (Mass., 12/82)	18%†	17.6%†
	14.4% (R.I., 4/84*)		
Nor. States Pwr.	14.7% (Minn., 6/82)	16.4%†	17.1%†
	14.5% (N.D., 1/82)		
	N.S. (S.D., 4/83)		
	15% (Wis., 7/83)		
PacifiCorp	Company wide:	15.6%†	13.44%†
	15.5% (Calif., 7/84)	N.A.	16.2%
	14.7% (Idaho, 12/84)	N.A.	12%
	13.75% (Mont., 2/84)	N.A.	13.6%
	15.75% (Ore., 11/84)	N.A.	16.2%
	15.25% (Wash., 2/84)	N.A.	10%
	N.S. (Wyo., 12/83)	N.A.	8.8%
Potomac Elec. Pwr.	14.9% (D.C., 12/82)	16.9%†	14.75%†
	15.5% (Md., 2/83)		
	15.5% (Va., 9/83)		
PS Colorado	14.4% (Colo., 5/84)	15.5%	13.2%
Rochester G&E	16% (N.Y., 7/84)	16.2%	16.5%
SCANA	14.25% (S.C., 2/84)	15.7%	14.1%
So. Cal. Edison	16% (Calif., 12/84*)	16.5%	17.6%
So. Indiana G&E	16.75% (Ind., 7/82)	17%	16.9%
Southwestern PS	16.17% (Tex., 6/82)	20.3%	21%
Tucson Elec. Pwr.	16.5% (Ariz., 12/81)	17.3%	21.7%
Union Electric	15.62% (Mo., 7/83)	16.9%†	16.5%†
	15.5% (Ill., 1983)		
	14.8% (Iowa, 2/84)		
United Illum.	16.4% (Conn., 12/84)	16.5%	19.2%
West. Mass. Elec. (NU)	16% (Mass., 7/84)	18.8%	10.2%
Wis. Elec. Pwr.	14.75% (Wis, 10/84*)	16.6%	17.8%
Wisconsin P&L	14.75% (Wis., 8/83)	16.3%	16.8%
Wisconsin PS	14.75% (Wis., 1/85*)	16.2%	15.8%

NOTE: * - Rates reduced in this order; N.S. - Not specified; N.A. - Not yet available;
† - Companywide return; CES - Commonwealth Energy System;
NEES - New England Elec. System; NU - Northeast Utilities

SOURCE: "35 Utilities Exceed Allowed Return; Regulator Reaction Varies-Widely," Electric Utility Week, April 1, 1985, page 1.

Excessive cash conditions cause a variety of reactions -- some not beneficial to ratepayers. For example, Forbes says that many utilities have become potential takeover targets. Others are diversifying into non-utility (as well as utility) areas. Still others increase dividends to stock holders.

Reactions of state regulators have varied widely according to Electric Utility Week. Some have issued orders that reduce rates. For example, Northeast Utilities stockholders may have to pay fuel costs that are normally recovered in rates. And actual rate reductions have been implemented in Massachusetts, Wisconsin and Delaware.

However, no action is planned against certain other utilities with high rates of return. For example, El Paso Electric earned 20.5 percent in 1983 and 20.4 percent in 1984 although "allowed" only a 16.4 percent return. And Southwestern Public Service earned 21 percent on equity in 1983 and 20.3 percent in 1984 while allowed a 16.17 percent return. Yet the Texas Public Utilities Commission has not announced actions reversing these returns.

Financial problems are not precluding most utilities from building "necessary" capacity. They are not building new capacity because it is not needed.

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ELCON

APPENDIX A

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

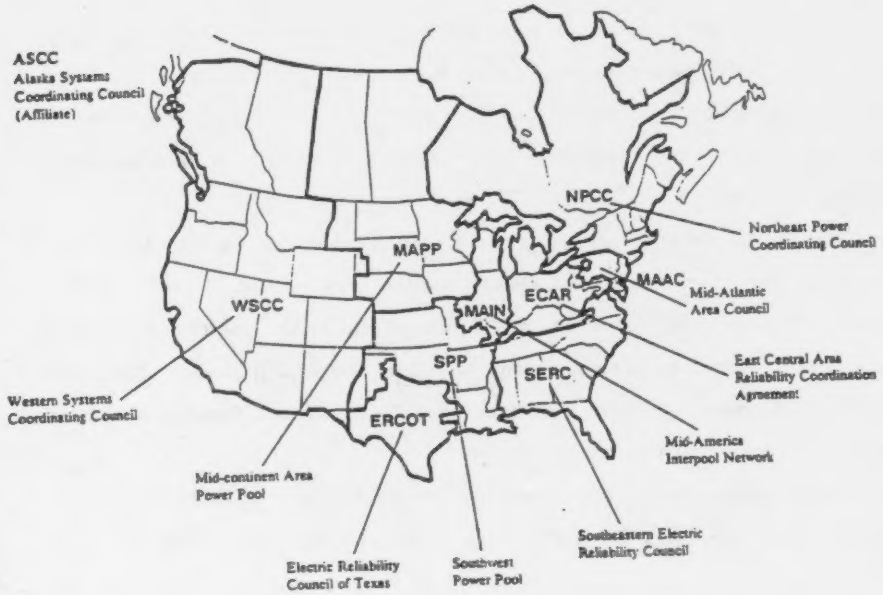
ASCC
Alaska Systems Coordinating Council (Affiliate)
NPCC
Northeast Power Coordinating Council
MAPP
MAAC
Mid-Atlantic Area Council
ECAR
WSCC
MAIN
East Central Area Reliability Coordination Agreement
SPP
SERC
Western Systems Coordinating Council
ERCOT
Mid-America Interpool Network
Mid-continent Area Power Pool
Southeastern Electric Reliability Council
Electric Reliability Council of Texas
Southwest Power Pool

TABLE 1

Peak Demand Grows as Forecasted by each NERC Region

Reserve Margin in % of Peak Demand

83-93 Peak Demand Growth Rate	NERC Region	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993
1.83	ECAR	37.8	40.8	44.0	43.9	44.0	43.4	39.4	37.0	34.4	32.4	31.5
4.13	ERCOT	25.2	21.8	20.9	21.2	22.3	18.8	20.5	18.8	17.8	17.5	17.1
1.19	MAAC	34.4	30.8	35.8	33.1	34.2	32.2	31.6	35.2	33.0	30.9	30.7
1.47	MAIN	17.6	24.8	30.5	34.6	37.9	35.7	33.5	31.5	29.3	26.6	24.4
2.55	MAPP-US	34.5	33.4	28.6	26.7	24.7	24.6	21.5	18.6	18.2	15.5	16.6
1.58	NPCC-US	34.2	34.1	35.7	39.9	40.2	37.2	34.7	32.7	36.6	33.5	30.9
2.28	SERC	28.6	37.3	36.2	35.0	34.6	32.6	33.3	29.9	29.2	27.2	25.0
2.54	SPP	29.2	30.1	38.0	37.6	33.4	29.7	26.0	25.6	24.3	22.0	22.0
2.52	WSCC-US	47.5	41.5	47.5	47.4	45.8	42.6	39.5	39.0	39.2	36.9	36.2
------	-------	----	----	----	----	----	----	----	----	----	----	----
2.26	NERC-US	33.3	35.1	37.3	37.4	36.9	34.6	32.8	31.2	30.5	28.3	27.2

TABLE 2

Peak Demand Grows at a Rate of 1.5 Times Each Region's Forecast

83-93 Peak Demand Growth Rate	NERC Region	Reserve Margin in % of Peak Demand										
		1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993
2.75	ECAR	37.8	33.0	37.0	37.2	36.7	35.7	31.2	28.1	24.9	22.2	20.3
6.20	ERCOT	25.2	20.8	17.4	15.0	14.4	8.3	7.8	4.1	1.2	-1.4	-3.8
1.79	MAAC	34.4	28.3	32.6	29.7	29.9	27.6	26.4	29.1	26.3	23.9	23.3
2.21	MAIN	17.6	20.0	26.2	29.5	32.1	29.3	26.6	24.1	21.5	13.4	15.7
3.82	MAPP-US	34.5	33.0	27.8	24.2	20.5	18.8	14.4	10.4	7.7	3.7	3.0
2.37	NPCC-US	34.2	31.9	32.3	35.0	34.1	30.8	27.7	24.7	27.5	24.2	21.1
3.42	SERC	28.6	28.3	28.4	26.7	25.8	23.1	22.8	18.8	17.4	14.5	11.9
3.81	SPP	29.2	26.9	32.7	30.5	25.4	20.7	16.1	14.6	12.4	9.1	7.9
3.78	WSCC-US	47.5	42.3	44.2	42.5	40.0	35.5	30.8	28.5	27.1	23.2	20.6
3.40	NERC-US	33.3	30.5	32.3	31.3	30.0	26.6	23.8	21.1	19.3	16.1	13.8

TABLE 3

Peak Demand Grows at a Rate of 2.0 Times Each Region's Forecast

83-93 Peak Demand Growth Rate	NERC Region	Reserve Margin in % of Peak Demand										
		1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993
3.66	ECAR	37.8	31.8	34.6	33.6	31.9	29.8	24.4	20.4	16.4	12.8	10.1
8.26	ERCOT	25.2	18.5	13.0	8.5	5.9	-1.6	-3.9	-9.0	-13.2	-17.1	-20.7
2.38	MAAC	34.4	27.6	31.0	27.5	26.9	24.0	22.0	23.9	20.5	17.6	16.3
2.94	MAIN	17.6	19.2	24.4	26.7	28.4	24.7	21.3	18.1	14.7	11.0	7.7
5.10	MAPP-US	34.5	31.4	24.7	19.7	14.8	11.8	6.3	1.3	-2.3	-7.1	-8.9
3.16	NPCC-US	34.2	30.9	30.3	31.9	30.1	25.8	21.9	18.2	19.9	15.9	12.1
4.56	SERC	28.6	26.9	25.6	22.6	20.4	16.5	15.0	10.0	7.5	3.7	0.3
5.08	SPP	29.2	25.3	29.5	25.9	19.4	13.6	8.0	5.2	2.0	-2.2	-4.5
5.04	WSCC-US	47.5	40.6	40.7	37.5	33.4	27.5	21.7	18.1	15.4	10.5	6.9
4.55	NERC-US	33.3	29.1	29.5	27.1	24.4	19.9	16.0	12.2	9.2	5.1	1.9

TABLE 4

No Additional Nuclear Units Are Added Beyond 1985

Reserve Margin in % of Peak Demand

83-93 Peak Demand Growth Rate	NERC Region	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993
1.83	ECAR	37.8	40.8	44.0	42.7	41.7	39.5	36.5	33.2	30.7	28.8	27.9
4.13	ERCOT	25.2	21.8	20.9	18.6	16.5	13.2	12.3	10.9	10.3	10.3	10.1
1.19	MAAC	34.4	30.8	35.8	33.1	31.2	29.3	28.7	27.2	25.1	23.1	23.0
1.47	MAIN	17.6	24.8	30.5	28.4	26.2	24.2	22.2	20.3	18.2	15.7	13.7
2.55	MAPP-US	34.5	33.4	28.6	26.7	24.7	24.6	21.5	18.6	18.2	15.5	16.6
1.58	NPCC-US	34.2	34.1	35.7	34.0	31.7	28.9	26.5	24.6	26.0	23.1	20.6
2.28	SERC	28.6	37.3	36.2	32.9	30.4	27.4	26.1	22.8	21.3	19.5	17.5
2.54	SPP	29.2	30.1	38.0	35.6	31.5	27.8	24.2	21.8	20.6	18.4	18.5
2.52	WSCC-US	47.5	44.5	47.5	45.9	42.8	39.7	36.6	34.9	33.8	31.6	31.0
2.26	NERC-US	33.3	35.1	37.3	35.1	32.7	30.0	27.7	25.3	24.0	22.0	21.0

TABLE 5

10 % Derating of All Coal-Fired Capacity Beginning in 1985

Reserve Margin in % of Peak Demand

83-93 Peak Demand Growth Rate	NERC Region	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993
1.83	ECAR	37.8	40.8	32.1	32.1	32.2	31.9	28.2	26.0	23.6	21.9	21.0
4.13	ERCOT	25.2	21.8	18.0	18.2	19.2	15.8	17.1	15.2	14.1	13.7	13.0
1.19	MAAC	34.4	30.8	32.4	29.7	30.8	28.9	28.3	32.0	29.8	27.8	27.5
1.47	MAIN	17.6	24.8	22.6	26.8	30.2	28.1	26.1	24.3	22.1	19.6	17.5
2.55	MAPP-US	34.5	33.4	20.3	18.3	16.4	16.3	13.3	10.7	10.2	7.7	8.5
1.58	NPCC-US	34.2	34.1	34.1	38.1	38.2	35.0	32.3	30.3	34.3	31.2	28.6
2.28	SERC	28.6	37.3	29.5	28.4	28.1	26.3	26.9	23.7	23.0	21.1	18.9
2.54	SPP	29.2	30.1	32.7	32.3	28.3	24.6	21.1	20.8	19.4	17.1	17.0
2.52	WSCC-US	47.5	44.5	44.0	43.9	42.3	39.1	36.1	35.7	35.7	33.4	32.7
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2.26	NERC-US	33.3	35.1	31.4	31.4	31.0	28.8	27.0	25.6	24.8	22.8	21.6

TABLE 6

Cogeneration / Alternate Energy Grow by 3000 MW per Year

Reserve Margin in % of Peak Demand

83-93 Peak Demand Growth Rate	NERC Region	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993
1.83	ECAR	37.8	40.8	44.0	43.9	44.0	43.4	39.4	37.0	34.4	32.4	31.5
4.13	ERCOT	25.2	21.8	24.8	28.7	33.1	32.7	37.2	38.0	39.4	41.4	42.8
1.19	MAAC	34.4	30.8	35.8	33.1	34.2	32.2	31.6	35.2	33.0	30.9	30.7
1.47	MAIN	17.6	24.8	30.5	34.6	37.9	35.7	33.5	31.5	29.3	26.6	24.4
2.55	MAPP-US	34.5	33.4	28.6	26.7	24.7	24.6	21.5	18.6	18.2	15.5	16.6
1.58	NPCC-US	34.2	34.1	35.7	39.9	40.2	37.2	34.7	32.7	36.6	33.5	30.9
2.28	SERC	28.6	37.3	36.2	35.0	34.6	32.6	33.3	29.9	29.2	27.2	25.0
2.54	SPP	29.2	30.1	39.1	39.6	36.4	33.5	30.7	31.2	30.5	28.9	29.6
2.52	WSCC-US	47.5	44.5	47.5	47.4	45.8	42.6	39.5	39.0	39.2	36.9	36.2
2.26	NERC-US	33.3	35.1	37.8	38.2	38.1	36.2	34.8	33.5	33.1	31.3	30.4

TABLE 7

Cogeneration / Alternate Energy Grow by 3000 MW per Year and Peak Demand Grows at a Rate of 1.5 Times Each Region's Forecast

Reserve Margin in % of Peak Demand

83-93 Peak Demand Growth Rate	NERC Region	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993
2.75	ECAR	37.8	33.0	37.0	37.2	36.7	35.7	31.2	28.1	24.9	22.2	20.3
6.20	ERCOT	25.2	20.8	21.2	22.1	24.5	21.0	22.8	21.0	19.8	18.5	17.3
1.79	MAAC	34.4	28.3	32.6	29.7	29.9	27.6	26.4	29.1	26.3	23.9	23.3
2.21	MAIN	17.6	20.0	26.2	29.5	32.1	29.3	26.6	24.1	21.5	18.4	15.7
3.82	MAPP-US	34.5	33.0	27.8	24.2	20.5	18.8	14.4	10.4	7.7	3.7	3.0
2.37	NPCC-US	34.2	31.9	32.3	35.0	34.1	30.8	27.7	24.7	27.5	24.2	21.1
3.42	SERC	28.6	28.3	28.4	26.7	25.8	23.1	22.8	18.8	17.4	14.5	11.9
3.81	SPP	29.2	26.9	33.7	32.5	28.2	24.3	20.5	19.6	18.1	15.4	14.6
3.78	WSCC-US	47.5	42.3	44.2	42.5	40.0	35.5	30.8	28.5	27.1	23.2	20.6
3.40	NERC-US	33.3	30.5	32.8	32.1	31.1	28.2	25.6	23.3	21.6	18.7	16.7

TABLE 8

Cogeneration / Alternate Energy Grow by 3000 MW per Year and Peak Demand Grows at a Rate of 2.0 Times Each Region's Forecast

Reserve Margin in % of Peak Demand

83-93 Peak Demand Growth Rate	NERC Region	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993
3.66	ECAR	37.8	31.8	34.6	33.6	31.9	29.8	24.4	20.4	16.4	12.8	10.1
8.26	ERCOT	25.2	18.5	16.6	15.3	15.3	9.9	9.4	5.8	2.7	-0.3	-3.2
2.38	MAAC	34.4	27.6	31.0	27.5	26.9	24.0	22.0	23.9	20.5	17.6	16.3
2.94	MAIN	17.6	19.2	24.4	26.7	28.4	24.7	21.3	18.1	14.7	11.0	7.7
5.10	MAPP-US	34.5	31.4	24.7	19.7	14.8	11.8	6.3	1.3	-2.3	-7.1	-8.9
3.16	NPCC-US	34.2	30.9	30.3	31.9	30.1	25.8	21.9	18.2	19.9	15.9	12.1
4.56	SERC	28.6	26.9	25.6	22.6	20.4	16.5	15.0	10.0	7.5	3.7	0.3
5.08	SPP	29.2	25.3	30.5	27.7	22.1	17.0	12.0	9.8	7.1	3.4	1.5
5.04	WSCC-US	47.5	40.6	40.7	37.5	33.4	27.5	21.7	18.1	15.4	10.5	6.9
4.55	NERC-US	33.3	29.1	29.9	27.9	25.6	21.4	17.7	14.1	11.4	7.5	4.4

TABLE 9

No Unit Retirements Plus
Cogeneration / Alternate Energy Grow by 3000 MW per Year
and Peak Demand Grows as Forecasted by Each NERC Region

83-93 Peak Demand Growth Rate	NERC Region	Reserve Margin in % of Peak Demand 1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993
1.83	ECAR	37.8	40.8	44.0	44.0	44.1	43.6	39.6	37.2	34.9	33.2	32.4
4.13	ERCOT	25.2	21.8	24.8	28.8	33.2	33.0	37.9	39.3	41.7	45.1	47.8
1.19	MAAC	34.4	31.0	37.9	36.0	37.6	35.5	35.6	39.2	37.5	35.6	35.4
1.47	MAIN	17.6	24.8	30.8	34.9	38.2	36.0	33.9	32.5	30.3	28.1	25.8
2.55	MAPP-US	34.5	33.5	28.8	26.9	24.9	25.6	22.4	19.6	19.3	16.6	18.1
1.58	NPCC-US	34.2	34.1	35.9	40.1	40.4	37.7	35.3	33.4	37.3	34.6	32.2
2.28	SERC	28.6	37.4	36.3	35.1	34.8	33.0	33.6	30.4	29.9	28.0	25.8
2.54	SPP	29.2	30.1	40.2	41.2	38.7	35.8	33.6	34.7	34.3	33.3	34.4
2.52	WSCC-US	47.5	44.5	47.6	47.6	46.7	43.6	40.6	40.2	40.9	38.9	39.3
2.26	NERC-US	33.3	35.1	38.1	38.7	38.9	37.1	35.8	34.8	34.7	33.3	32.8

TABLE 10

No Unit Retirements Plus
Cogeneration / Alternate Energy Grow by 3000 MW per Year
and Peak Demand Grows at a Rate of 1.5 Times Each Region's Forecast

Reserve Margin in % of Peak Demand

83-93 Peak Demand Growth Rate	NERC Region	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993
2.75	ECAR	37.8	33.0	37.0	37.3	36.8	35.8	31.4	28.3	25.4	22.9	21.1
6.20	ERCOT	25.2	20.8	21.2	22.2	24.6	21.2	23.5	22.1	21.8	21.7	21.4
1.79	MAAC	34.4	28.5	34.6	32.6	33.2	30.8	30.2	32.9	30.6	28.4	27.7
2.21	MAIN	17.6	20.0	26.5	29.8	32.3	29.5	27.0	25.1	22.4	19.8	17.1
3.82	MAPP-US	34.5	33.1	28.0	24.4	20.8	19.7	15.3	11.3	8.8	4.8	4.3
2.37	NPCC-US	34.2	31.9	32.5	35.1	34.3	31.2	28.2	25.4	28.1	25.2	22.3
3.42	SERC	28.6	28.3	28.5	26.9	26.1	23.4	23.1	19.3	18.0	15.2	12.6
3.81	SPP	29.2	26.9	34.9	34.0	30.3	26.4	23.2	22.8	21.5	19.3	18.8
3.78	WSCC-US	47.5	42.3	44.3	42.7	40.8	36.4	31.9	29.6	28.6	25.0	23.3
3.40	NERC-US	33.3	30.5	33.1	32.6	31.8	29.0	26.7	24.5	23.1	20.5	18.9

TABLE 11

No Unit Retirements Plus Cogeneration / Alternate Energy Grow by 3000 MW per Year and Peak Demand Grows at a Rate of 2.0 Times Each Region's Forecast

Reserve Margin in % of Peak Demand

83-93 Peak Demand Growth Rate	NERC Region	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993
3.66	ECAR	37.8	31.8	34.6	33.7	32.0	30.0	24.6	20.6	16.8	13.5	10.8
8.26	ERCOT	25.2	18.5	16.7	15.3	15.3	10.1	10.0	6.7	4.4	2.3	0.1
2.38	MAAC	34.4	27.7	33.0	30.3	30.1	27.1	25.7	27.6	24.6	21.8	20.4
2.94	MAIN	17.6	19.2	24.7	27.0	28.6	25.0	21.7	19.0	15.6	12.3	9.0
5.10	MAPP-US	34.5	31.5	24.9	20.0	15.0	12.6	7.1	2.2	-1.4	-6.1	-7.6
3.16	NPCC-US	34.2	30.9	30.5	32.1	30.2	26.3	22.4	18.8	20.5	16.8	13.3
4.56	SERC	28.6	26.9	25.7	22.8	20.7	16.8	15.2	10.5	8.1	4.3	0.9
5.08	SPP	29.2	25.3	31.6	29.2	24.1	18.9	14.5	12.8	10.2	6.9	5.2
5.04	WSCC-US	47.5	40.6	40.9	37.6	34.2	28.4	22.7	19.1	16.7	12.1	9.3
4.55	NERC-US	33.3	29.1	30.3	28.4	26.2	22.1	18.6	15.2	12.7	9.1	6.4

TABLE 12

No Unit Retirements

Reserve Margin in % of Peak Demand

83-93 Peak Demand Growth Rate	NERC Region	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993
1.83	ECAR	37.8	40.8	44.0	44.0	44.1	43.6	39.6	37.2	34.9	33.2	32.4
4.13	ERCOT	25.2	21.8	20.9	21.2	22.4	19.0	21.2	20.0	20.1	21.3	22.0
1.19	MAAC	34.4	31.0	37.9	36.0	37.6	35.5	35.6	39.2	37.5	35.6	35.4
1.47	MAIN	17.0	24.8	30.8	34.9	38.2	36.0	33.9	32.5	30.3	28.1	25.8
2.55	MAPP-US	34.5	33.5	28.8	26.9	24.9	25.6	22.4	19.6	19.3	16.6	18.1
1.58	NPCC-US	34.2	34.1	35.9	40.1	40.4	37.7	35.3	33.4	37.3	34.6	32.2
2.28	SERC	28.6	37.4	36.3	35.1	34.8	33.0	33.6	30.4	29.9	28.0	25.8
2.54	SPP	29.2	30.1	39.2	39.1	35.7	31.9	28.9	29.2	28.1	26.3	26.7
2.52	WSCC-US	47.5	44.5	47.6	47.6	46.7	43.6	40.6	40.2	40.9	38.9	39.3
2.26	NERC-US	33.3	35.1	37.7	37.9	37.7	35.5	33.9	32.5	32.1	30.4	29.6

TABLE 13

U.S. Reserve Margins Under Alternative Supply and Demand Scenarios

Scenario:	Peak Growth Rate :	Reserve Margins										
		1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993
(a) Base Case	2.26	33.3	35.1	37.3	37.4	36.9	34.6	32.8	31.2	30.5	28.3	27.2
(b) High Growth	3.40	33.3	30.5	32.3	31.3	30.0	26.6	23.8	21.1	19.3	16.1	13.8
(c) Double Growth	4.55	33.3	29.1	29.5	27.1	24.4	19.9	16.0	12.2	9.2	5.1	1.9
(d) Nuclear Moratorium	2.26	33.3	35.1	37.3	35.1	32.7	30.0	27.7	25.3	24.0	22.0	21.0
(e) Coal Derating	2.26	33.3	35.1	31.4	31.4	31.0	28.8	27.0	25.6	24.8	22.8	21.6
(f) Alternative Energy	2.26	33.3	35.1	37.8	38.2	38.1	36.2	34.8	33.5	33.1	31.3	30.4
(g) High Growth & Alternative Energy	3.40	33.3	30.5	32.8	32.1	31.1	28.2	25.6	23.3	21.6	18.7	16.7
(h) Double Growth & Alternative Energy	4.55	33.3	29.1	29.9	27.9	25.6	21.4	17.7	14.1	11.4	7.5	4.4
(i) Alternative Energy & No Retirements	2.26	33.3	35.1	38.1	38.7	38.9	37.1	35.8	34.8	34.7	33.3	32.8
(j) High Growth & Alternative Energy	3.40	33.3	30.5	33.1	32.6	31.8	29.0	26.7	24.5	23.1	20.5	18.9
(k) Double Growth & Alternative Energy	4.55	33.3	29.1	30.3	28.4	26.2	22.1	18.6	15.2	12.7	9.1	6.4
(l) No Unit Requirements	2.26	33.3	35.1	37.7	37.9	37.7	35.3	33.9	32.5	32.1	30.4	29.6

ELCON

APPENDIX B

ELECTRIFICATION OF AMERICAN INDUSTRY

Dr. John A. Anderson
Executive Director
Electricity Consumers Resource Council

A Presentation at the
American Public Power Association's
Engineering and Operations Workshop

March 7, 1985
Atlanta, Georgia

It's a pleasure to be here today to discuss the electrification of American industry. Where is electricity used today? Where will it be used tomorrow? There are few questions as full of mystery and yet as crucial to both your industry and the industries I represent as these.

The Electricity Consumers Resource Council (ELCON), as many of you probably know, represents large industrial users of electricity -- big companies with facilities in most of the 50 states and numerous foreign countries. We have 20 members at present, and they account for a huge amount of electricity use. ELCON members consume approximately five percent of all electricity generated in the United States.

Our members represent a good cross-section of United States industry -- steel, aluminum, chemicals, glass, industrial gases, textiles, motor vehicles and food. They have many interests in common.

But probably more fascinating for today's discussion are the enormous differences in how ELCON members -- and indeed, all industrials -- use electricity. We are not talking about a homogeneous group. We cannot speak of electrification in industry with the same generalities that we apply to residential electrification. This audience knows a lot about the electricity demand of home appliances and a good deal about where home electricity conservation might continue to occur. Although you may have a big problem predicting growth in the number of households, you are going to have a bigger one predicting growth in industrial demand. Why? Industrial firms not only are all different, they also have a proven record of dramatic change.

Things have come a long way since 1882, when Thomas Edison first supplied service to a small section of lower New York from his Pearl Street generating station. Back then, electricity was used primarily for lighting; industrial power came from steam and water. However, industry rapidly electrified, thanks largely to advancements in electric motors.

At the turn of the century, less than ten percent of all motorpower used in manufacturing was electric-powered. Today, nearly 100 percent of it is.

So the question is, "How to gauge the possibility for change in use of electricity by all of those furnaces, pumps, compressors, saws, shredders, grinders, spinners, heaters, dryers and so forth, out there in United States industry?" I hope I can help.

But first, I want to give you some quick examples of the tremendous number of different uses of electricity among ELCON's members.

- The aluminum industry uses most of its electricity for smelting -- that is, turning powdered aluminum oxide (or alumina) into primary aluminum. Smelting involves passing electrical charges through alumina and other chemicals. During this electrolysis process, the oxygen atoms break away from the alumina leaving primary aluminum, which is molded in ingots and other shapes. It takes six to eight KWH to produce one pound of aluminum.

- The steel industry uses huge quantities of electricity to drive rolling mills and pollution abatement equipment. Hundreds of motors are used -- some as large as 15,000 horsepower. More recently, with the availability of large amounts of scrap steel to melt down, there has been an expanded use of electric arc furnaces. These furnaces contain three large electrodes -- each typically two feet wide -- which produce an arc from the electric charge whose heat melts down scrap.

- In the manufacture of industrial gases, electricity is used to drive pumps and compressors that compress air so that its component gases can be separated by distillation. Electricity for these pumps and compressors can account for 70 percent of the total production costs.

- In the chemical industry, chlorine and caustic soda are produced by electrolysis of sodium chloride brine. It can take anywhere from 1,600 to 2,900 KWH per ton for this process. Alternatively, phosphorous is produced through an electric arc process -- somewhat similar to aluminum. Phosphate rock is combined with coke and silica and electrically charged in a furnace. This process releases a gas stream containing elemental phosphorus and carbon monoxide.

- The glass industry uses mostly natural gas to fuel furnaces, but many of these furnaces also contain electric "boosters" both to add heat and to create a stirring action.

- Motor vehicle manufacturing involves a number of different processes that are electricity-intensive. Air handling equipment is driven by electric motors; liquids to treat and wash metals are heated and moved by electricity; painting, machining, welding, soldering and compressing air are all done by electricity.

Table 1 presents statistics on electricity - intensive industries. These data indicate clearly that American industry today is highly electrified.

TABLE 1

STATISTICS ON ELECTRICITY-INTENSIVE INDUSTRIES

Industry	SIC code	Value of shipments (10^6 1980$)	Electricity purchased (10^6 kWh)	Electricity cost as percent of: Value added	Electricity cost as percent of: Value of shipments	Electricity rate ¢/kWh (1982$)	Ratio to industrial average rate (3.84¢/kWh)
Cotton seed oil mills	2074	1,033.7	540.7	10.7	2.0	4.61	1.20
Manufactured ice	2097	169.6	460.7	15.6	11.0	4.70	1.23
Particle board	2492	512.4	825.1	11.4	4.8	3.44	0.90
Alkalies and chlorine	2812	1,354.1	10,679.5	45.5	19.6	2.89	0.75
Industrial gases	2813	1,539.6	11,958.6	42.4	24.5	3.66	0.95
Other industrial inorganic chemicals	2819	12,095.9	37,082.0	13.9	7.5	2.63	0.75
Carbon black	2895	498.0	540.4	13.3	3.5	3.78	0.98
Reclaimed rubber	3031	38.3	75.4	12.2	7.8	4.62	1.20
Cement, hydraulic	3241	3,962.4	6,237.9	15.3	8.2	4.08	1.06
Lime	3274	598.8	813.8	10.8	5.1	4.38	1.14
Mineral wool	3296	2,235.4	2,703.5	7.3	4.0	3.82	0.99
Electrometallurgical products	3313	1,249.3	6,814.3	42.0	13.8	2.94	0.77
Malleable iron foundries	3322	521.2	1,015.5	11.9	7.0	4.17	1.09
Primary zinc	3333	413.1	1,457.8	51.7	8.3	2.67	0.70
Primary aluminum	3334	6,979.5	72,278.1	38.3	15.6	1.75	0.47
Other primary nonferrous metals	3339	1,906.6	4,279.4	15.6	5.1	2.66	0.69
Carbon and graphite products	3624	1,183.3	2,171.8	7.5	4.2	2.64	0.69

Source: United States Census Bureau, 1980 Annual Survey of Manufacturers: Fuels and Electric Energy Consumed, August 1982, as reported in: United States Congress, Office of Technology Assessment, OTA-0-204, Acid Rain and Transported Air Pollutants: Implications for Public Policy (June 1984), p. 200.

FUTURE INDUSTRIAL ELECTRIFICATION

The electrification of industry occurred because it made good business sense -- it lowered total costs of production. Similarly, electrification will occur in the future when it makes economic sense, not simply because a new technology is developed.

Where can we expect additional electrification? Let's break electricity use into end-use applications to target those areas where we might expect growth. Table 2 provides such a segmentation.

TABLE 2

ELECTRICITY USE BY INDUSTRIAL SECTOR

1980 (10^9 kWh)

Industrial Sector	Total Electricity Use	End-Use Application Motor Drives	Electro-lytics	Process Heating	Light and Space Heat
Process-related industries					
Chemicals	145.0	96.9	31.7	0.4	16.0
Paper products	76.0	61.6	—	—	14.4
Food products	43.3	35.1	—	2.7	5.5
Petroleum and coal products	37.7	31.3	—	—	6.4
Textile mill products	26.1	20.6	—	0.5	5.0
Rubber and plastics	21.9	19.0	—	—	2.9
Lumber and wood products	14.8	11.0	—	0.5	3.3
Printing and publishing	9.7	7.1	—	—	2.6
Apparel	6.0	4.4	—	—	1.6
Subtotal	380.5	287.0	31.7	4.1	57.7
Fabricated metals industries					
Machinery (nonelectric)	30.7	20.9	0.1	8.8	0.9
Transportation equipment	30.0	22.8	—	3.2	4.0
Electrical equipment	27.2	22.5	—	0.5	4.2
Fabricated metal products	25.3	10.8	—	13.2	1.3
Instruments	6.0	4.2	—	—	1.8
Miscellaneous manufacturing	3.6	2.5	—	—	1.1
Subtotal	122.8	83.8	0.1	25.7	13.2
Primary metals industry	175.4	50.9	71.3	33.2	20.0
Stone, clay, and glass products	30.8	24.7	—	2.4	3.7
Other	7.4	5.4	—	—	2.0
Total	716.9	451.8	103.1	65.4	96.6

Sources: United States Bureau of the Census, 1980 Annual Survey of Manufacturers, and estimates by Resource Dynamics, as reported in: "Electricity: Liner on Industrial Productivity," EPRI Journal (October 1984), p. 13.

Motor Drives

By far the largest single industrial electrical end-use involves motor drives. The alternative to electromechanical drives is direct conversion of fuels into mechanical energy. The equipment that converts fuel to mechanical energy (diesel engines, steam generators, etc.) is costly to purchase and maintain, it often creates noise, heat, exhaust gases, or other unwanted effects, and it is often relatively inefficient. For example, it may convert less than 30 percent of the energy in the fuel into mechanical power while more than 80 percent of the energy content of electricity is converted into useful work. Not surprisingly, more than three-fifths of all electricity used by industry today is for motor drives.[1]

Although there are few motor drive conversions left to be made, what we will see is (1) continued movement toward energy efficient motors for retrofits and replacements and (2) expanded use of electronic, adjustable-speed drives (ASDs).

Energy-efficient electric motors can result in less electricity consumption for the same work than standard motors; however, they cost more. While it might not make economic sense to replace a perfectly good motor today with a more energy efficient one, many industrials have established a corporate policy of replacing old or worn motors with these more efficient ones.

Even greater motor drive electrification potential lies with ASDs. Electricity consumption can be cut substantially (50 percent or more in certain applications) by careful control of the speed of motors.[2] The potential is particularly great for fans and pumps. Mechanical or hydraulic ASDs have limited applicability, but electronic ASDs are relatively inexpensive and well suited for retrofits.

Electrolysis and Electric Melting

Approximately 15 percent of all electricity used by industry today is for electrolysis and electric melting -- predominantly in primary metals and chemicals. There is real potential for change in this area.

> Steel - In 1959, less than ten percent of all steel was produced in electric arc furnaces. Today, due primarily to the availability of scrap, nearly one-third of it is. Between 1970 and 1982, energy use per ton fell by 25 percent, while

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[1] "Electricity: Lever on Industrial Productivity," EPRI Jounal (October 1984), p. 13.

[2] Ibid., p. 11.

the use of electricity per ton increased 20 percent.[3] Electricity use in the steel industry is expected to continue to grow. Indeed, some experts see it growing from today's level of 30 percent of total energy use to more than 40 percent within a decade.[4] Beyond that, some predict that plasma arc technology will replace the blast furnace altogether, leading to even further growth in electricity use.

Glass - All-electric glass-melting furnaces have been developed as an alternative to gas-fired regenerative furnaces, although only a small amount of glass is electrically melted today. Electric furnaces are about 3½ times as thermally efficient as conventional gas furnaces, and are nonpolluting. However, electric furnaces are not economic unless the ratio of electric to gas prices is below 3½ to 1, which is generally not the case today. Even so, some experts predict changes in relative prices may result in an increasing amount of glass production is likely to be done electrically.

Process Heating

Approximately ten percent of today's industrial electricity is used for process or electro-heating. However, since electricity offers simplicity of operation, minimum maintenance, versatility of application, cleanliness and control, direct process heating with electricity seems to have a bright future. Specifically:

Resistance furnaces - Heat treating in resistance furnaces permits uniform heat distribution with accurate temperature control. Resistance furnaces range from small, bench-top models to large industrial heating facilities. Electric furnaces eliminate the contaminated atmospheres created in oil and gas-fired furnaces. This reduces scrap losses due to surface defects and reduces the need for mechanical finishing after treatment.

As an example, an aluminum jobbing foundry switched from oil to electricity for resistance heating.[5] Its electric load increased from 470 to 700 KW, but this was more than offset by a reduction in melting cost per pound and a drop in melt losses. Indeed, in this application, the total cost of production was almost halved!

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[3] Institute for Energy Analysis, Oak Ridge Associated Universities, The Roll of Electricity in American Industry (Oak Ridge, Tennessee: June 1984), p. 14.

[4] "Electricity: Lever on Industrial Productivity," op. cit., p. 12.

[5] Ontario Hydro, Toronto, "Switch to electric melting pays off for aluminum foundry," Initiatives and Payback, Number 1 (January 1984), p. 1.

Induction furnaces - In an induction furnace, an oscillating magnetic field generates current in the workpiece so that it is heated to the precise depth needed. This can be done in a fraction of the time required in gas-fired furnaces. Induction furnaces primarily are used today for surface hardening. However, they also can be used for annealing, glazing, soldering and billet heating.

Induction furnaces represent a proven technology. Four kinds of metal fabrication industries (transportation equipment, machinery, electrical equipment, and metal products) used 22 billion KWH in such processes in 1980. Their consumption represented only three percent of total industrial electricity consumption and only one-third of the total electricity used for process heat. The future for expanded induction furnace applications looks good.

Other Technologies Affecting Industrial Electrification

Electrification has the potential to greatly enhance industrial productivity as a variety of new technologies are perfected and implemented. It is beyond the scope of this paper to describe in detail these technologies. However, I would like to cite a few examples.

Robotics - Robotics is a rapidly developing industrial trend toward computerized control of the manufacturing process. Robots are computer-controlled, reprogrammable, movable tooling devices.

Good data are not available even on the number of robots currently in operation, much less on their future. One study reports 6,000 robots currently in use, 40 percent of them in the motor vehicle industry.[6] This study further suggests that there could be as many as 240,000 robots in use by 1990. Industries such as machinery and tools, electrical machinery, electronics, metals fabrication and foundries are likely candidates for increased robotics.

Program Logic Controls (PLCs) - PLCs represent another aspect of computerized control of manufacturing. Computers monitor and adjust various manufacturing operations to maintain correct speed, content and other critical parameters.

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[6] Science Management Corporation, conducted for EPRI, The Impact of Industrial Robots on Electric Loads in U.S. Industry, Number EM-3325 (February 1985).

For example, an ELCON steel company uses PLCs to control rolling mills. The product must move at increasing speed as it is compressed thinner by each mill stand. PLCs control the precise adjustment of each mill stand and the speed of process to assure the production of a product that meets specifications. Additionally, the company uses PLCs to monitor and take bath samples in electric arc furnaces. A significant problem in melting 100 percent scrap is controlling the content of carbon and alloy, each of which must be kept at delicate levels. Computers can monitor the blend of the bath and quickly analyze the content. This reduces the time required to melt and allows precise predictions of correct power needs.

Another ELCON company, a beer company, uses PLCs to control bottle lines. The PLC coordinates the beer coming to the bottlers, the fillers, the timing of the labeler, and the packaging. The PLC reduces the need for manpower, increases the speed of the bottling operation, increases quality control and lowers cost.

Energy Management Systems (EMS) - EMSs represent yet another aspect of computerized control of industry. EMSs have potential application in virtually every industrial process from controlling electric arc furnaces to turning on and off lights.

For example, the steel company mentioned earlier uses an EMS to monitor power demand. In one application, the computer makes 23 checks on electricity consumption in each 30-minute demand period. The computer checks accumulated consumption and projects consumption at the end of the demand period. If the projection exceeds the programmed limit, the furnace is selected for possible control. Careful demand control both reduces the company's bill and improves the utility's operating efficiency by raising load factors and reducing demand spikes. The utility thus is able to operate with fewer spinning reserves.

The beer company discussed earlier uses many EMSs. In one application, an EMS is used to monitor large (300-400 hp) ammonia compressors used in cooling and refrigeration. The EMS automatically reduces load (or even shuts down completely) lightly loaded compressors.

Freeze crystallization - Freeze crystallization substitutes mechanical energy for thermal energy for separating materials. Traditionally, liquids are boiled (usually with fossil fuels) and vaporized to separate certain elements. Freeze crystallization uses electricity to drive a refrigeration compressor to freeze the liquids, allowing them to be separated. The thermodynamic efficiency may be two to ten times greater than vaporization.[7]

Commercial Electrification - Great opportunities exist for further electrification in the commercial sector. An example underscores this point.[8]

Traditionally, Burger King restaurants relied heavily on gas. A new Burger King in Cleveland, however, is almost all-electric. It incorporates the following electrically-driven innovations:

- o Heat from the kitchen ventilation exhaust system is reclaimed to warm the building and eliminate cold drafts.
- o Heat from the compressor gases exhausted from walk-in coolers and freezers is reclaimed to heat water.
- o A special ventilating system is installed over the bank of electric fryers. This reduces the air makeup requirements of the kitchen, facilitates faster capture of exhaust heat, vapors, smoke and odors, and lowers air conditioning tonnage.
- o A special hood over the broiler captures about 70 percent of the heat normally exhausted outside and uses it to preheat kitchen makeup air.
- o Finally, a microcomputer-based EMS system uses time-of-day scheduling to control all heating, ventilating, air conditioning, compressor motor loads, and electric fryers.

Since space conditioning costs in restaurants amount to about 40 percent of total energy costs, careful control of all space conditioning made good economic sense.

What does all of this mean?

I see exciting new applications of both existing and new technologies that clearly suggest increased electrification in nearly every American industry. Some authors predict a small potential for electrification in non-process manufacturing, since these operations require primarily mechanical energy, which is already electrically driven.[9] They suggest that the greatest potential for further electrification lies in process manufacturing such as primary metals, stone/clay/glass, petroleum, chemicals, paper and food.

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[7] "Electricity: Lever on Industrial Productivity," op. cit., p. 13.

[8] This case study is described in: "Comin' right up: one all-electric Burger King," Energy Management Technology (Waker-Davis Publications, Willow Grove, PA: December/January 1985), p. 38.

[9] Institute for Energy Analysis, op. cit., p. 20.

I see further electrification in both process and non-process manufacturing. Table 3 highlights this assertion. However, the implications for utilities may not be as they initially appear. Increased electrification may not add to your electricity sales. Here's why.

TABLE 3

IMPACT OF NEW TECHNOLOGY ON THE INTENSITY OF INDUSTRIAL ELECTRICITY USE

Application	Estimated 1983 Consumption (%)	Largest Users	Impacting Technologies by 2000	Probable Trend in Electricity Intensity
Electromechanical drives	70	• Chemicals • Pulp and paper • Foods • Primary metals • Petroleum refining • Textiles	• High-efficiency motors • Adjustable speed drives • Cogeneration	Down
Electrolysis	15	• Primary metals • Chemicals	• Improved cell efficiency • Chloride process • Membrane cells • Electrochemical synthesis • Membrane separation	Down
Electroheat	10	• Primary metals • Metal fabrication • Chemicals • Foods • Pulp and paper • Textiles	• Plasma reduction • Plasma melting • Induction heating • Laser heating • Electron beam heating • Electroslag casting • Plasma chemistry • Microwave and radio frequency heating • Infrared heating • Ultraviolet curing	Up
Other	5	All	• Robotics • Improvements in HVAC	Down

Source: Philip Schmidt, as reported in: "Energizing American Industry for Global Competition," EPRI Journal (December 1983), p. 22.

Electrification has both positive and negative impacts on load growth

Electrification in certain industrial processes will increase total electricity consumption. Increased use of electric arc furnaces in steel production or electric furnaces in glass melting, expanded use of electric resistance and induction furnaces for heat treating, and other such movements toward electricity-driven technologies will tend to increase electricity consumption.

However, other electrification applications have been shown to result in decreased electricity consumption. For example:

High efficiency motors result in a direct, often significant, reduction in consumption.

Electronic adjustable speed drives also result in direct electricity savings.

Improved electrolysis efficiencies allow the same amount of product to be made with less electricity.

Some of the most dramatic developments in electrification may cut two ways, adding to, while at the same time reducing or controlling electricity demand. Two examples illustrate this paradox.

Robots are being used increasingly in motor vehicle manufacturing. Certainly they will use electricity. A point often overlooked, however, is that a primary electricity use in motor vehicle manufacturing is for space conditioning. Robots do not need air conditioned work spaces. Thus, the increase in electricity consumption attributable to the operation of the robot is at least partially offset by reduced use due to changes in space conditioning. It is too early to tell which impact will be larger.

Computers are being used in numerous industrial applications. Operating these devices certainly requires electricity. However, the computer applications of which I am aware nearly always result in net electricity savings by cutting down on wasted, useless and lost energy.

Increased Electrification may Result in Increased Energy Sales but not Peak Load Growth

Electrification may increase offpeak consumption or may involve manufacturing processes that can be interrupted. Many electric arc furnaces are operated during the night. The steel is then reheated for processing during the day. Additionally, operators of arc furnaces may be willing to have service interrupted if offered an appropriate economic incentive, even when the interruption results in an increase in the number of KWH used per ton of output. Similar situations exist in many other primary metal and chemical operations where opportunities for electric-intensive innovations appear great. All customers of a utility may benefit where electrification results in increased KWH consumption without increases in peak load.

Industry may Self- or Cogenerate Significant Proportions of New Load

At the turn of the century, industry generated nearly 60 percent of the nation's electricity. By 1980, industrial generation represented less than three percent of all generation.

However, changing economic conditions are making self- and cogeneration more attractive. For example:

- Electricity produced from generating units costing $4,000/KW may cost consumers in excess of 150 mills/KWH.
- Traditional utility accounting methods "front-load" cost recovery from customers.
- Regulatory bodies often approve rates that require industrial customers to pay a disproportionately large share of the total costs of the utility.

Industrial (as well as other) electricity consumers are reacting to these and other pressures by carefully reevaluating the economics of self- and cogeneration. Indeed, it now seems likely that industrial cogeneration capacity alone will be in excess -- perhaps significantly in excess -- of 50,000 MW by the year 2000. These facilities may range from large, coal-fired facilities to small gas-fired turbines. ELCON member companies already operate cogeneration facilities of hundreds of megawatts each. On a smaller scale, a 65 KW cogeneration unit is presently providing most of the electricity, heating and cooling needs of a McDonald's restaurant in San Diego.[10] To the extent that industry generates the electricity used for increased electrification, utility sales will not increase and, indeed, may decrease.

Rising Electricity Prices may Make Continued Operation of Key Sectors of American Industries Uneconomic in the United States

The industrial demand for electricity is not perfectly inelastic. Rising electricity prices will choke off electricity consumption. Rapidly rising electricity prices will significantly impact future electrification. Rising electricity prices may result from the completion of an extremely expensive new generating unit, the cancellation of an unneeded unit, the passage of acid rain legislation, the imposition of energy taxes , or a variety of other reasons. The cause is not the important point in this discussion. The result, however, is very important.

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[10] "McDonald's Eyes More Cogeneration One to Pilot Job," Energy Users News, January 14, 1985, p. 2.

For example, aluminum companies in the United States pay on average more than 25 mills for electricity, while their competitors in foreign countries pay on average less than 17 mills. With electricity constituting approximately one-third of the total costs of production, this differential makes it questionable whether the basic aluminum industry in the United States will be able to continue operation.

Other electricity intensive industries face similar competitive disadvantages, although perhaps to a smaller degree. If significant portions of basic industry (aluminum, steel, chemicals, etc.) find it impossible to continue to operate in the United States, electrification may result in electricity comprising a larger share of a smaller total market.

ESTIMATING FUTURE ELECTRIC DEMAND

Accurate estimates of future electric demand are difficult to make under the best of circumstances. Significant electrification by industry compounds these difficulties.

I know of no easy answer to the problem. I suggest a process which, I believe, could help utilities plan for the future.

It is called: Get to know your industrial.

Residential demands can be projected by econometric techniques, primarily because of the homogeneity of the consumption characteristics of the customers in the class.

However, industrial demands must be projected on a plant-by-plant basis. Large industrial facilities are not alike. Each is designed, constructed, maintained and operated as a unique entity. Each uses electricity in its own way.

Certainly the industrial cannot predict exactly its future electricity consumption, but the industrial does have a good idea of the significant changes expected in the future. And since it is in the industrial's best interest to create a situation where an adequate and reliable supply of electricity is assured at reasonable prices, it is in the industrials' best interest to share information with the supplying utility.

Similarly, surely it is in the utility's best interest to establish an open, arms-length, trusted relationship with its major industrial customers.

That's one of the best ways to plan for the future.

Mr. **Doane**. Thank you very much, Dr. Anderson.

There are no questions at this time. However, the committee may well submit to each of you written questions to be then responded to in writing over the course of the next 2 weeks.

On behalf of the chairman, I would like to thank each of you again very much for your excellent testimony and for your patience in waiting until the last panel of the day.

The hearing is adjourned.

[Whereupon, at 4:50 p.m., the hearing was adjourned.]

APPENDIXES

APPENDIX I

Responses to Additional Committee Questions From Witnesses Appearing July 23, 1985

GRI
gas research institute

OFFICIAL COMMITTEE FILE

1331 Pennsylvania Avenue, N.W.
Suite 730 North
Washington, D.C. 20004-1703
202/662-8944

DANIEL A. DREYFUS
Vice President,
Strategic Analysis & Energy Forecasting

August 20, 1985

SENATE COMMITTEE ON
ENERGY AND NATURAL RESOURCES
RECEIVED
AUG 21 1985
WASHINGTON, D.C. 20510

The Honorable James A. McClure
Chairman
Committee on Energy
and Natural Resources
United States Senate
Washington, DC 20510

Dear Mr. Chairman:

Thank you for your letter of August 5 concerning my testimony at the Committee's hearing on the outlook for the electric utility industry. I appreciated having the opportunity to make a presentation on this issue which is very significant to all sectors of the energy industry.

I am enclosing my responses to the questions posed by Senator Bumpers and transmitted by your letter.

With best wishes,

Daniel A. Dreyfus

/cbm

Enclosure

cc: The Honorable Dale L. Bumpers
Dr. Benjamin S. Cooper
Mr. David E. Doane

Gas Research Institute, 8600 West Bryn Mawr Avenue, Chicago, Illinois 60631 312/399-8100

Responses by Dr. Daniel A. Dreyfus
to
Questions by Senator Dale Bumpers

1. Question: What are the risks and costs of over and under estimation, and who should bear them?

   Response: The risk of overestimation of electricity demand, if the electric utilities and the regulatory community act upon the projections, is to construct new generating capacity prematurely. The trend in recent years toward very large generating units with long construction lead times makes such errors of judgment difficult to reverse. The sudden and generally unexpected downturn in energy demand resulting from the oil price shocks, behavioral responses to the energy crisis, and the prolonged global recession caught the electric utilities in the midst of a massive construction program. The numerous powerplants in various stages of construction that were found to be premature have proven to be costly, either to complete or to abandon.

   Traditionally, utilities were permitted to recover a rate of return on "used and useful" investment in new capacity. Even if the construction program proved to be too ambitious, the ratepayers were required to amortize the investment in a timely manner. In the past, however, excess new capacity was not particularly difficult to deal with. The units were smaller, and the new plants were generally more economical to operate than the older units. Premature retirement of older plants, therefore, often improved overall system economies and benefited the ratepayer.

   In the current financial situation, excess new capacity is likely to be an economic burden on the system.

   The regulatory community, therefore, has applied more stringent criteria to determine the "value" of construction in progress and of completed but "excess" capacity. Utilities have not always been allowed the return on investment that was anticipated by the management, the stockholders, and the financial community when the investments were made. At present, the risk of an investment which might prove to be in excess of the need for new capacity has been transferred very heavily to the utilities and their investors. The dramatic downgrading in the bond ratings of the electric utilities as an industry is sufficient proof of the financial community's belief that there has been a change in the burden of risk.

   Underestimation of electricity demand also implies a risk, but it is more difficult to appraise or to locate. If electricity demand outstrips the utility construction program, several outcomes are possible. When the historical statistics and peak demand shortages demonstrate the problem, public opinion and public policy will have to seek solutions. The financial community is not compelled to lend money to utilities. Hence, the future costs of financing will be higher, based upon the investors' perceptions of greater risk. Unplanned and expedient capacity additions are also apt to be less economic than a carefully planned construction program. Ratepayers (or taxpayers) will ultimately have to pay these increased costs.

If the reliability of electric supplies is substantially degraded as this situation evolves, the costs of power curtailments and interruptions could be significant in terms of industry and business closings, public safety and police activity, or other emergency costs. Extensive emergency backup systems for vital services, communications, computer systems, and even residences will surely be less efficient and more costly than maintaining a sound central utility service. All of these costs will be borne by ratepayers or by the general public.

2. Question: In the past, forecasts have been highly inaccurate for the most part. Is there any hope that they have or will improve?

   Response: The history of forecasting is mixed. During the relatively stable 1950s and 1960s, simple extensions of established trend lines and relationships produced reliable forecasts. In the mid-1970s, for a variety of reasons, discontinuities and radical changes in the structure of the U.S. economy, and especially in energy relationships, made energy forecasting haphazard.

   There is no methodology for forecasting that would have captured the unprecedented developments in energy supply and demand over the past decade. In retrospect, it should have been obvious that the scenarios which would have resulted from the extension of existing trends were unstable and, therefore, that some reaction was probable. Some commentators, in fact, did point out that the projected situations were impossible. The more difficult task was to predict what would happen instead. I am not aware of any forecasts of the early 1970s or before that accurately portrayed the subsequent developments, in the general energy outlook, although some of the specific factors were predicted.

   Modern forecasting techniques provide the capability to account for very complex interrelationships among many variables. They can project scenarios that are internally consistent and that are consistent with historical experience and physical limitations. In other words, they can describe in detail scenarios that could rationally occur. They are especially good at projecting rational scenarios in which current trends and relationships continue.

   If such scenarios are viewed, not as predictions, but as evidence of the eventual impact of current trends, they can be important decision tools. The implications of the scenarios can provide a basis for action to avoid undesirable conditions, to monitor potentially troublesome trends, and to intuitively predict the probable behavioral changes that will result from the trends.

   For example, the energy projections of the early 1970s stated that energy prices would rise and energy supplies would be scarce if the then existing behavior and relationships continued. Governments, businesses and individuals responding to those expectations took millions of decisions to avoid the unpleasant consequences of the predictions. Collectively, the decisions helped to alter the trends and made the forecasts wrong.

Certainly, no one would be better off if the unacceptable conditions then being forecast had come about. The forecasts were an effective instrument of decision, and they served a purpose.

From a policy planning viewpoint, it is unlikely that the reliability of forecasts will improve; but the effective use of forecasts could make them much more valuable.

WHARTON
ECONOMETRIC
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ASSOCIATES

3624 Science Center Philadelphia, Pa. 19104 215/386-9000 Telex/TWX: 710 6700575 Wharton

August 23, 1985

Honorable James McClure
U.S. Senate
Committee on Energy and Natural Resources
Washington, DC 20510

Dear Senator McClure:

I have received your followup mailing to the July 23 hearing on the adequacy of electricity supply in the 1990s. Senator Bumpers submitted two followup questions, which I answer below.

1. What are the risks and costs of over- and underestimation, and who should bear them?

   Underestimation of regional electric demand growth is likely to lead to inadequate capacity expansion programs, with the following costs to the region.

   - Mild underbuilding would make electricity unneccessarily expensive, as utilities turn to higher-cost oil-fired or gas-fired generation, or imported electricity. This is Wharton's estimate of what will actually happen in some regions in the early 1990s.

   - If capacity expansion is even slower than we expect, consequences for electricity price and availability are likely to be even more severe. Rolling brownouts or even blackouts become a possibility, with more severe economic consequences.

   - In either case, the costs to the region are slower economic growth and increased inflation.

   - If demand is significantly less than expected, and capacity in the 1990s is unnecessarily large, the average cost per kilowatt hour is likewise higher than necessary. If this cost is passed through to consumers, the result is unnecessarily high inflation and slow growth. If the cost is not passed through to consumers, the result is unnecessarily low return to stockholders. This will tend to increase the cost of borrowing for the overbuilding utilities.

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Honorable James McClure
August 23, 1985
Page Two

- The responsibility for decisions concerning electric power supply should reside with both the local PUCs and the electric utilities. Such joint decision-making should probably be accompanied by risk-sharing between stockholders and ratepayers.

2. Is there any hope that the accuracy of utilities' demand forecasts will improve?

   - One of the points of Wharton's testimony is that electric utility demand projections vary widely from region to region. Utilities' forecasts will probably continue to be imperfect: some of their estimates are likely to be too high, and some too low. In some regions where demand forecasts are low and construction programs are correspondingly slow, baseload electricity supply will be insufficient to meet demand, and there will be increased reliance by utilities on more expensive purchased power.

   - While utilities' forecasts have been inaccurate in the past, many utilities are now devoting more resources to the development of more accurate projections. They are hiring employees with the necessary skills to develop models to forecast regional electricity demand. In addition the staffs at a number of public utility commissions are also developing projections — which can be used as an additional check on utilities' load forecasts.

   - In the past, utilities have not paid enough attention to the impact of price increases and conservation measures. However, these factors are now incorporated into most utilities' projections. The current risk is that utilities will be too conservative in their forecasts, given the penalties that have resulted from previous construction programs.

Sincerely,

Mark French

Mark French
Manager of Energy and
Commodity Economics

MF/rlm

STATE OF CONNECTICUT
DEPARTMENT OF PUBLIC UTILITY CONTROL

SENATE COMMITTEE ON
ENERGY AND NATURAL RESOURCES
RECEIVED
AUG 27 1985

OFFICIAL COMMITTEE FILE

August 22, 1985

The Honorable James A. McClure
Chairman, Committee on
Energy and Natural Resources
United States Senate
Washington D.C. 20510

Dear Senator McClure:

Thank you for the opportunity to testify at the Committee's recent hearing on the potential for regional shortages of electrical power in the U.S. by the early 1990's. I hope that my input will assist the Committee as it addresses this critical issue.

In that regard I am attaching comments on the three follow-up questions you forwarded to me in your letter of August 5. If you have need for any further input, please feel free to contact me.

Sincerely,

John T. Downey

John T. Downey
Chairperson per RMA.

att.

One Central Park Plaza • New Britain, Connecticut 06051
An Equal Opportunity Employer

Comments on Follow-up Questions Related to Recent Hearings on Potential for Regional Shortages of Electrical Power

by John T. Downey, Chairperson
Connecticut Public Utility Control Authority

A. From Senator Bumpers:

1. "Do you think that state commissions should have greater authority to refuse to pass through all or part of a FERC-approved rate? Do you believe that the current balance of state and federal regulatory authority is fairly defined, or would you recommend change? If you do, what kind of changes?"

To the extent that the FERC has jurisdiction in a particular area, it does not appear appropriate for state commissions to be able to refuse to pass through a FERC approved rate. At issue, however, is whether the jurisdictional lines between FERC and state regulation should be redrawn. In my view the balance between state and federal regulatory authority should be changed, to give state regulators greater authority over all the operations of the utilities under its jurisdiction. Regarding wholesale purchases of electric power, when both utilities are regulated by state commissions, state regulation of wholesale rates might be warranted.

Currently, all costs incurred in the process of any wholesale electric purchase by a utility, or any purchase of natural gas by a local gas distribution company from its pipeline supplier(s), must be passed on by state regulators to the local utility's ratepayers, if the sale has been approved by the FERC. This does not enable the state commission to examine the purchases to determine whether a local utility is operating to provide its services to its ratepayers in the most efficient, least cost, manner possible, or subsequently, if warranted, to deny the cost pass-through.

Any resolution of this problem in the public interest requires cooperation and understanding among the state and federal agencies concerned. How to promote such cooperation is a question of some urgency. In theory, a state commission is free to intervene in FERC proceedings to make its views known. In practice, many state commissions lack the resources to participate on an ongoing basis at the FERC.

One means of enhancing cooperation might be the establishment of Federal/State Joint Boards to address specific issues. The experience of such Boards in dealing with the telecommunications industry should be studied.

Another vehicle which deserves serious consideration is the Regional Board, perhaps typified by the Northwest Power Planning Council. Such a Board or Comission, with representatives from each state in the region, might usefully deal with issues of capacity needs and capacity planning, and conceivably with regional wholesale rates. The concern is that we not lay yet another layer of regulation on an already burdened industry.

2. "Do you believe that utility companies are structuring their relationships and transactions in ways to ensure FERC jurisdiction? If so, do you see this as a problem?"

While I am not aware of any actions by utilities in Connecticut which would remove jurisdiction from the state level, there is always the potential for such action. Clearly it is simpler for a utility which serves in several jurisdictions to be regulated at the federal rather than at the state level. In addition, some utilities may hope to receive more favorable treatment at the federal level. I do see this as a potential problem, for it would reduce even further the ability of state regulators to act in a coherent manner in ensuring least cost provision of utility services to customers. "Forum-shopping" is likely to be disruptive and productive of confusion and ill will.

From Senator Ford:

> "If you were an electric utility executive, would you build a major baseload power plant (1200+ megawatts) today unless you were ordered to do so by a regulatory agency?"

Prudent management dictates that before proceeding with any major construction project, or any other undertaking requiring large capital expenditure, a utility executive should ensure that a broad consensus exists in support of the project. It is incumbent upon the responsible utility executive to work to create that consensus, and not to wait for regulators or general circumstances to identify and require the particular course of action the utility should take. In the case cited above, at the very least it would be necessary for the executive to demonstrate that the new powerplant met the criteria of least costly and most efficient means of meeting the customers' needs. In turn, it is incumbent on regulators and legislators to create conditions which encourage and assist utilities to meet their public service obligations.

OFFICIAL COMMITTEE FILE

CP&L
Carolina Power & Light Company
P. O. Box 1551 • Raleigh, N. C. 27602
(919) 836-[illegible]

SHERWOOD H. SMITH, JR.
Chairman/President

SENATE COMMITTEE ON
ENERGY AND NATURAL RESOURCES
RECEIVED
AUG 29 1985
WASHINGTON, D.C. 20510

August 26, 1985

Honorable James A. McClure
Chairman, Committee on Energy
  & Natural Resources
361 Senate Dirksen Office Building
Washington DC 20510

Dear Senator McClure:

Thank you for your letter of the 5th regarding my participating in the July 23 hearing. I appreciated the opportunity to appear before the Committee on Energy and Natural Resources and to participate in the discussion on future energy supplies.

In answer to the question you sent with your letter of August 5, as a general proposition, under the present regulatory and financial conditions, it is doubtful that it will be practical to try to build new large base-load generating plants in many parts of the country. Whether "I" would seek to do so would depend upon several things. For example, without major and dramatic changes in the NRC, one could not think about building another nuclear plant. The long lead time involved, continual changes, and the lengthy adversarial licensing system, etc., would absolutely prevent this. As to a fossil or hydro plant, whether or not "I" would seek to build one would depend upon the response to the project from the appropriate licensing and rate regulatory bodies. Unless there was an assurance of some stability and predictability of regulation over the time period of construction and putting the plant into rate base, then it would not seem to be possible to go forward.

Sincerely,

Sherwood H. Smith, Jr.

Sherwood H. Smith, Jr.

SHSjr/k

OFFICIAL COMMITTEE FILE

New England Electric

New England Electric System
25 Research Drive
Westborough, Massachusetts 01582
Tel. (617) 366-9011 TWX 710-390-0732
Cable: NEELECSYS WTBO

John F. Kaslow
Executive Vice President
Chief Operating Officer

August 14, 1985

SENATE COMMITTEE ON
ENERGY AND NATURAL RESOURCES
RECEIVED
AUG 19 1985
WASHINGTON, D.C. 20510

The Honorable James A McClure
Chairman, Committee on Energy and
Natural Resources
United States Senate
Washington, D. C. 20510

Dear Senator McClure:

It was a pleasure for me to testify before the Senate Committee on Energy and Natural Resources on July 23 and I thank you for offering us the opportunity. Surely, the issue of ensuring an adequate future supply of electric energy at reasonable cost is a priority issue for both utilities and their customers.

Your August 5 letter forwarded a question from Senator Ford and I am enclosing our response to that question for the hearing record.

I hope that the recent hearing provided you and your associates on the Committee with the constructive input that will facilitate dealing with future power supply needs.

Sincerely,

John F. Kaslow

The name "New England Electric System" means the trustee or trustees for the time being (as trustee or trustees but not personally) under an agreement and declaration of trust dated January 2, 1926, as amended, which is hereby referred to, and a copy of which as amended has been filed with the Secretary of the Commonwealth of Massachusetts. Any agreement, obligation or liability made, entered into or incurred by or on behalf of New England Electric System binds only its trust estate, and no shareholder, director, trustee, officer or agent thereof assumes or shall be held to any liability therefor.

Response to Senator Ford Question

Q. As an electric utility executive would you build a major base load plant (1200+ MW) today unless you were ordered to do so by a regulatory agency?

A. As a preface to our answer to the question, I would like to reiterate our company's approach to planning for the future. We define our approach as BALANCED PLANNING - a process which applies consistent and unbiased economic criteria to options to decrease demand as well as to options to increase supply.

If the results of our Balanced Planning evaluation process indicated that new base load capacity was the economic choice for our customers, we would attempt to build that base load capacity.

The application of "consistent and unbiased economic criteria", however, requires dealing with issues implicit in the question posed by Senator Ford.

First - what are the options for base load capacity? For base load capacity to be constructed in New England - or for virtually any location in the U.S. - coal fired capacity is the only option. For supply from outside the U.S. (Canada, for example), nuclear and possibly hydro are options.

Second - what is the likelihood of obtaining satisfactory regulatory treatment if the decision is made to build rather than import base load capacity? Our company's wholesale business is regulated by the Federal Energy Regulatory Commission (FERC). We believe that FERC has a history of balancing customer and shareholder interests in a very fair and evenhanded manner. As a result, the threat of poor or unfair regulatory treatment at the FERC level would not be an impediment to proceeding with the most economic solution.

However, we could not dismiss entirely - and would attach some risk factor to - the warning signals we see in the decisions of some state regulatory commissions across the country. For example, the disallowance of Construction Work in Progress and failure to fully allow total final costs in rate base are causes for deep concern.

Third - can we actually build the unit?

Assuming that we have the financial capability to complete the project, the major risk - and indeed threat - in this area is the licensing and permitting process. The maize of siting and environmental regulations provides almost endless opportunities for intervention and delay in major projects. This risk factor would clearly be incorporated and weighed in our evaluation. The prospects of superimposing acid rain legislation/regulation on top of an already complex Clean Air Act provides some tough hurdles for new coal fired capacity - and this, too, would require some risk weighted penalty in an evaluation.

In summary, if our Balanced Planning process indicated new, base load capacity was the economic choice, we would pursue that option. However, as risk factors associated with base load capacity increase relative to other demand/supply options, the probability that base load capacity will win the competition diminishes.

AMERICAN ELECTRIC POWER *Company, Inc.*

AEP

1 Riverside Plaza (614) 223-1000
P.O. Box 16631
Columbus, Ohio 43216-6631

W. S. WHITE, JR.
Chairman of the Board
and
Chief Executive Officer
(614) 223-1500

SENATE COMMITTEE ON
ENERGY AND NATURAL RESOURCES
[illegible]
AUG 23 1985

August 21, 1985

OFFICIAL COMMITTEE FILE

Hon. James A. McClure, Chairman
Committee on Energy and Natural Resources
United States Senate
Washington, DC 20510

Dear Senator McClure:

This is in response to your letter to me dated August 5, 1985, in which you requested a written answer to a question posed by Senator Wendell H. Ford as a follow-up to my testimony before the Committee on Energy and Natural Resources on July 23. Senator Ford's question reads as follows: "As an electric utility executive, would you build a major baseload power plant (1200+ megawatts) today unless you were ordered to do so by a regulatory agency?"

In my testimony on July 23, I directed the Committee's attention to the increasingly prevalent governmental and regulatory second guessing, with the benefit of hindsight, of electric utility managements' investment decisions made in good faith many years before under an entirely different set of circumstances. At the time, I pointed out that should electric utilities in this country be prevented from earning sufficient return on their investments to enable them to attract new capital -- or, should the risk associated with investment in new power supply facilities become too great -- new power supply facilities just will not be built to replace worn-out equipment and to provide for new load growth: The trust of utility managements in the integrity of their government and the trust of utility investors in the "regulatory compact" that was supposed to assure a fair return on their investment in return for a limit on their profits, once lost, will not be easy to restore.

Since any commitment by an electric utility to build a major baseload power plant of 1200 or more megawatts (as posed in Senator Ford's question) would require raising by the utility of many hundreds of millions of dollars in capital from the investors in both equity and debt securities, such a facility just could not be built -- regardless of whether a regulatory agency did or did not order the utility to do so -- unless the utility were able to raise the necessary capital. The raising of such capital from the investing public entails the utility management's appraisal of the soundness of the investment involved, both in terms of its expectation of a fair return on such investment and in terms of the risk associated with it. Recent regulatory experiences of many electric utilities across the country are not at all reassuring in this regard.

One of the most disturbing aspects of recent regulatory history is the increasingly frequent lack of institutional continuity in regulatory decision-making: a strong endorsement by a regulatory commission of a major power supply project at one point in time does not provide any real assurance to the electric utility that the same regulatory commission (but with a different membership) would not oppose the continuation and completion of that very project at a later point in time.

In the specific context of the American Electric Power System, the generating capacity presently in place or nearing completion is expected to be sufficient to meet our customers' requirements into the latter 1990's. Today, the AEP System is supplying large amounts of electric power and energy to neighboring utilities that have the need for such power and energy. As our system load continues to grow, we expect to "recapture" the power and energy that is currently available for sale to other electric utilities, so as to meet the needs of our own customers. Because of these circumstances, we expect the AEP System to be affected by future generating capacity shortages somewhat later in time than many of our utility neighbors. Nevertheless, the AEP System is bound to be affected eventually, unless the present trend in regulatory policies is stopped and then reversed.

Finally, given AEP's current situation, we do not have to make the decision today raised by Senator Ford's question. However, if we were faced with that decision, it would be very difficult to give an affirmative answer, considering the regulatory attitude that presently prevails.

I hope that the above comments will be helpful to the Committee on Energy and Natural Resources in its further deliberations on the matter of future adequacy of our nation's electric power supply.

Sincerely,

W. S. White, Jr.
Chairman of the Board

jc

Arizona Public Service Company
P.O. BOX 21666 • PHOENIX, ARIZONA 85036

KEITH TURLEY
CHAIRMAN AND CHIEF EXECUTIVE OFFICER

August 30, 1985

OFFICIAL COMMITTEE FILE

SENATE COMMITTEE ON
ENERGY AND NATURAL RESOURCES
RECEIVED
SEP 3 1985
WASHINGTON, D.C. 20510

Honorable James A. McClure
Chairman
U. S. Senate
Committee on Energy and Natural
Resources
Washington, D.C. 20510

Dear Senator McClure:

This letter is in response to your August 5, 1985 letter concerning follow-up questions to my testimony before the Senate Committee on Energy and Natural Resources.

Let me say again that I appreciated the opportunity to speak before your committee, and hope that my input was helpful to your deliberations.

The answers to the follow-up questions are enclosed. I will be pleased to respond to any further questions.

Sincerely,

Keith Turley

KT:mft

Enclosure

RESPONSES TO QUESTIONS ASKED
BY SENATOR DANIEL J. EVANS

Q. 1.(a) The completion of a new transmission intertie between the Pacific Northwest and the Inland Southwest was recently evaulated by the Western Area Power Administration (WAPA). The date of such report is January 1985. The report points out the benefits of a new transmission intertie and economic feasibility. A copy of such report is not included because of its size.

APS is presently taking the lead in putting together a basic study plan to refine the economic benefits; determine actual transactions that may be feasible; evaluate financial arrangements (i.e., funding, ownership, etc.); and refine environmental and technical concerns. This effort is just beginning. In the meantime, WAPA is soliciting interest and proposed uses for the new intertie. The APS and WAPA process will be merged ultimately.

Q. 1.(b) The specific lower bounds of cost-competitiveness have not been investigated. This will become clearer after completion of more in-depth feasibility studies and agreement on specific commercial conditions for transaction over the proposed Inland Intertie. Since the characteristic of each entity is different, each party will do its own individual analysis to determine cost-competitiveness.

The original study has shown benefits at exchange levels as low as 500 MW, which is approaching the minimum amount of diversity need. Such exchanges would defer peaking resources in the Southwest and base load sources in the Northwest.

Q. 1.(c) Part of the work in the study plan mentioned in the answer to question 1.(a) would include the investigation of the exact location of the line. The probable location of the southern terminal is Mead Substation, located in southern Nevada. The northern terminal will be determined in the study plan. The original broad feasibility studies prepared by APS and the Intercompany Pool in the northwest were based on a D. C. transmission system that had a northern terminal at Midpoint, Idaho and a southern terminal in the Phoenix area.

Q. 2. The most likely arrangement for development of an Inland Intertie will be a consortium of southwest utilities dealing with a consortium of northwest utilities, which may include Bonneville.

Q. 3. Based on all previous studies of a Northwest-Southwest transmission tie and the recent WAPA study, there are only enough benefits to justify a single line. The Inland Intertie line, if built, would be in place of the line already authorized.

Q. 4. Although agreements have not been written regarding the 3rd party financed projects, APS has given its input to the proposed projects of what generally would be an acceptable type of financial agreement. "Pay-for-performance" type of arrangements allocate much of the risk of performance on the side of the constructors.

-more-

This is essential since the purchaser of the power will have little input into the design, construction and operation of the facilities. The constructor will have to evaluate the delicate balance between capital cost, market price and system reliability, knowing that if the plant does not perform within agreed-upon standards, he will not be paid. Likewise, the purchaser will have the risk of being required to accept the power when produced, which may be at times when more economical sources are available.

Q. 4.(a) The three projects have not set specific dates for in-service yet. This will be determined by the market. The most likely time frame is the mid to late 1990's.

Q. 4.(b) Specific power costs have not been presented, but the costs will have to be competitive with what a utility can do on its own. The specific cost will ultimately be determined by the market and the negotiation of specific agreements.

Q. 4.(c) There is certainly no reason why the alternative of 3rd party financed projects cannot be expanded to cover all available markets. The location of specific types of projects will be based on many variables, such as area growth, area load characteristics, present resource mix, available natural resources, etc. The use of 3rd party financed projects should be viewed as another alternative available to the utility industry to meet electrical demand.

RESPONSE TO QUESTION ASKED
BY SENATOR WENDELL H. FORD

The specific answer to your question is "no." However, I am optimistic enough to believe that a method can be worked out so that all the interests impacted by the construction of a new base load power plant can work out an understanding of how such an undertaking can take place while addressing everyone's interests. As I stated in my testimony, this may require changes in both federal and state laws.

# # # # # # # # #

Attachment to 9/23/85
ltr. from Chairman
Taliaferro, Pa. PUC

CHAIRMAN LINDA C. TALIAFERRO
PENNSYLVANIA PUBLIC UTILITY COMMISSION

RESPONSE TO QUESTIONS PRESENTED BY UNITED STATES SENATE COMMITTEE ON ENERGY AND NATURAL RESOURCES

Q. Do you think that State Commissions should have greater authority to refuse to pass through all or part of a FERC-approved rate? Do you believe that the current balance of state and federal regulatory authority is fairly defined, or would you recommend change? If you do, what kind of change?

I do believe that State Commissions should have greater authority to refuse to pass through all or part of a FERC-approved rate.

The Pennsylvania Commission has ruled that a state does possess a limited ability over the pass-through FERC-approved rates. In In Pike County Light & Power Co. v. Pa. PUC, 465 A.2d 735 (1983), the Commission refused to pass through in retail rates the expense incurred by Pike in purchasing power (a wholesale transaction) from its affiliate in New York State - Orange & Rockland. This action was upheld in the Pennsylvania state courts.

This disallowance was not achieved by applying state rate-making policy to Orange & Rockland's costs to produce a different (and lower) wholesale rate than that approved by FERC. Rather, the disallowance was based on a determination of imprudency on Pike's part in not purchasing power from available, lower cost, alternative sources other than Orange & Rockland. Many previous unsuccessful state Commission efforts to block the pass through of FERC-approved rates were based on a "recalculation" of the FERC rate using state ratemaking policies.

Recent FERC opinions seem to support the concept behind the Pike County decision. That is, FERC may set the rate at which power is sold at wholesale in interstate commerce; however, the states may evaluate the prudency of the buying utility's decision and refuse to include all or part of the wholesale expense in retail rates. See 15 FERC ¶61,264 at 61,019 (1981).

While my Commission's disallowance of a FERC-approved rate rested on the Pennsylvania jurisdictional utility's prudence in choosing among alternative energy sources, such potential adjustments are rare and difficult to calculate.

One specific change which could be made to federal law would be the explicit confirmation of a state's authority to review the prudency of a retailer's (state jurisdiction) decisions to purchase energy.

The imbalance between state and federal ratemaking authority is most clearly evident in the area of natural gas service. The major component of an individual customer's gas bill is the cost of natural gas set by the FERC. A Commission has the "honor" and ends up with the rsponsibility for approving rates which reflect substantial costs imposed beyond the Commission's authority. A state commission is particularly helpless where a gas distributor is linked to only one interstate pipeline. While FERC's focus has been on rates which recover expenses incurred, little concern about the affect of decisions on the ultimate consumers seems to be factored into FERC decisions. Similar FERC pricing of electrical supplies would lead to furthering this regulatory imbalance.

Regulation on the state level is more subject to the pressures of our political system. This is true no matter what method is employed to appoint public utility regulators. The impact on the ratepayers and their reactions are everyday facts of life for state regulators. This is one reason that state commissions are becoming more active in FERC proceedings. Under a recent change in state law in Pennsylvania, my Commission is charged with evaluating gas distribution company efforts to represent their customers' best interests before the FERC.

Ultimately, the same issues and many of the same pressures which are involved in state regulation will be brought to bear more forcefully on the FERC regulatory process.

Q. Do you believe that utility companies are structuring their relationships and transactions in ways that ensure FERC jurisdiction? If so, do you see this as a problem?

There has been some action taken by Pennsylvania utilities to ensure FERC jurisdiction. Restructuring occurred in the gas industry to separate production and distribution systems. Major gas companies have not added new gas wells to their plant investment for rate base purposes, but have relied instead on federal pricing. Obviously, they believe that this results in higher earnings. As I mentioned earlier, even this type of pricing has not evaded the notice of the Pennsylvania legislature. My Commission is now required by law to examine a gas utility's purchasing practices each time it changes its rates. We specifically examine the purchasing policy to ensure "least cost procurement" of national gas.

In another instance the members of the Allegheny Power System sought and received the approval of the Pennsylvania Commission to invest in a separate company, Allegheny Generating Company. This new company owns a portion of the Bath County Pumped Storage Project in Virginia. The utilities contended that this project could be financed at a lower cost through this organizational arrangement.

The cost of the electricity from the Bath Project is controlled by a FERC approved formula. Under this ratemaking approach, the costs of the generating company would be included in a rate which would be periodically adjusted. Such a rate, of course, provides little incentive to keep costs down and the facility operating efficiently and effectively. Pennsylvania's recourse may be to utilize a "Pike County" analysis of alternative cost examination (see answer to question #1).

FERC's ratemaking policies seem to encourage the use of such a formula when the seller is a company formed to own the generating asset and the buyers are affiliates of each other and the seller.

Clearly differences in ratemaking policy and authority exist between FERC and Pennsylvania. For example, FERC permits rates to become effective after one day suspensions and also permits Construction Work in Progress in rate base. In Pennsylvania, CWIP inclusion in rate base is severely limited by statute and the rate requests of major electric utilities are subject to nine months (initial 60-day notice period and seven months of suspension) of investigation before rates can become effective. In view of the difference in ratemaking policy and the fact that state regulators see, hear and respond to the conditions within their state, it is not surprising that utilities would attempt to shield their operations behind the "friendlier" confines of FERC regulation.

The response to artificial "regulator shopping" by utilities will be a combination of state and federal actions. The more a federal agency takes over from a state regulatory agency, the more the same issues and pressures shift to the federal agency. The FERC should be more sensitive to "prudency issues" and the concept of stockholders sharing with ratepayers the costs of excess generating capacity.

In view of the current discussions of regionalization and joint ownership of power supplies as well as experimental programs to lessen regulation, further efforts will have to be made to ensure that states maintain overview or, at a minimum, have direct input into the design and execution of such proposals.

Although current Pennsylvania statutes require a significant amount of overview by the Commission of the utilities' transactions with their affiliates, there are methods available which would allow the formation of holding companies or non-regulated subsidiaries, without our prior review or approval. Our statutes envision affiliates providing services to the regulated utilities but not the reverse situation. Utilities may also be allowed to use internally generated funds to establish and fund a subsidiary which operates beyond the Commission's direct control.

Because of lack of state regulators' input and lack of public understanding of the limitations state regulators face, problems could exist in the future. Given my Commission's present authority over the transfer of assets from a regulated utility, I am not greatly concerned about the possibility of an electric utility totally removing its generating capacity from our regulation. However, in view of the need to limit financial risks and pressures of major construction projects and to avoid the development of excessive generating capacity, I would not be surprised if future generating stations were organized as to intentionally avoid state regulation.

Q. If you were an electric utility executive, would you build a major base load power plant (1200+ megawatts) today unless you were ordered to do so by a regulatory agency?

In answer to your question, I would decide whether or not to build a new generating station on the basis of my criteria test results. Construction of a major base load power plant is probably the most important corporate decision that an electric utility executive must make in his professional career. I consider a major base load plant as one that equals or exceeds 10% of a utility's existing installed capacity. I mention that figure because the installed capacity of our major electric utilities in Pennsylvania range from 870 megawatts to 8,360 megawatts.

The cost to the ratepayers of a small utility's investing in 87 megawatts is as burdensome to its ratepayers as a large utility investing in 836 megawatts. Many important factors must be considered before the final decision is made. Recently the Pennsylvania Commission conducted a thorough investigation before permitting the expense involved to be passed along to customers when the facility is found to be used and useful. A responsible utility executive, therefore, is aware that the Commissioners will not accept a rate request unless the utility can prove to our satisfaction that the investment is prudent.

To withstand the prudency test the utility must explain in detail its conservation programs; the accuracy of its load forecasting; the efficiency of its existing generating stations; the power available from the interconnection systems and the contributions of cogeneration and small scale hydro in the foreseeable future. This criteria is critical to the utility before it makes a decision to begin construction because failure to satisfactorily answer these questions during an investigation risks denial of the entire cost by this Commission.

Your question about 1,200 megawatts of capacity is extremely important inasmuch as the concept to fill a need goes beyond the decision to build. A major base load station of that size requires a similar reserve capacity to replace it during unexpected emergencies. The Pennsylvania Commission of 1965 that I mentioned in my previous testimony recommended 20% reserve margin for each operating system to be prepared for emergencies and unexpected load growth. That recommendation was made on the basis of base load generating stations with individual units of 400 to 600 megawatts.

When the electric utilities decided to build stations with units in the 1,050 to 1,200 megawatt range, it dramatically changed the reserve requirements. The unexpected loss of a unit or station of that size either to man-made or natural causes would place an immediate burden on the system's replacement capacity to serve the connected load. As a consequence, the utility encounters additional expense almost totally affecting the cost benefit ratio that made the large central station appealing to the decision-making management. The reserve requirement then increased to approximately 35%.

The driving principle of utility management should be "avoid risks whenever possible."

If investment in a dedicated conservation program combined with increased plant efficiency and accurate load forecasting would equal or be less than investment in a new generating unit I would prefer to avoid the seven to ten years of construction problems. If I have achieved my conservation goals, optimized plant efficiency, satisfactorily refined load forecasting and could not execute a purchase power agreement at a reasonable rate, then and only then would I consider a construction program.

The construction program would be discussed with the appropriate regulatory agencies and local government officials prior to making a firm commitment. That very important step is a recent legislative requirement (Act 123) in Pennsylvania and may prove to be one of the most cost effective decisions that a responsible utility executive makes in his career.

Construction of a large base load generating station, no matter what its fuel source, presents many serious financial, social, political and environmental risks. Before opening his company up to such risks, a manager should endeavor to meet the perceived need for additional generating capacity by other means. The last step would be the commitment to the unilateral construction of a large base load generating facility. The utility manager must be able to clearly demonstrate that every other alternative had been seriously pursued before the decision to construct a unit had been made. Changes in rate design, conservation and co-generation must be actively tapped to offset the need for new generation. Uprating of existing facilities and life-extensions of existing facilities must be seriously evaluated and attempted. Attempts must be made to purchase available existing economic supplies and attempts must be made to find potential co-owners for any new generating facilities.

These steps differ from the prior status quo approach of each company building their own facilities to meet the expected needs of their customers. Of course, the conditions which fostered the status quo have also changed. We seem to be moving to sharing of ownership and power pooling as ways to avoid the impacts of significantly more expensive plants and the problems of excessive generating capacity. Pools also help avoid dependence on oil generation and can also help overcome a utility's short term local supply problems. All these go to avoiding risks.

The idea of reducing land use area when building smaller stations and transportation for both fuel and waste is sensible. The implications of additional transmission lines and impact of the unexpected failure of a large central unit on the customers of several utilities can quickly reverse the reasonableness of the suggestion.

Appendix II

Responses to Additional Committee Questions from Witnesses
Appearing July 25, 1985

POST-HEARING QUESTIONS AND ANSWERS

Relating to the

JULY 25, 1985, HEARING

Before the

COMMITTEE ON ENERGY AND NATURAL RESOURCES
UNITED STATES SENATE

WITNESS: HELMUT MERKLEIN
ADMINISTRATOR, ENERGY INFORMATION ADMINISTRATION

QUESTIONS FROM SENATOR BUMPERS

ELECTRICITY SHORTAGES HEARING, JULY 25, 1985

Question: What load control programs can be implemented in a 3 to 5 year period? What amount of capacity can they be expected to save by the mid-1990s?

Answer: From a technological standpoint the opportunity exists to expand load control programs where they can contribute to improved electricity supply. These programs include time-of-day pricing, efficiency improvement initiatives (such as installation of insulation in homes), direct control of end-use devices, interruptible service, cooperative usage agreements among several users, and many others. Technology is available for direct control of end-use devices such as water heaters, air conditioners, and electric heating. A wide diversity of additional load control programs could be implemented in the commercial and industrial sectors as well.

The determination of which control programs to implement varies utility-by-utility because of the diversity of utility generation mix, load characteristics, capital and variable costs, consumers' freedom to choose, and acceptance of the various measures. As a result, the reduction of capacity requirements due to load control programs is difficult to determine. The order in which programs are introduced, their costs, and the mix of programs for a given utility are important factors in the savings calculation. In addition, load control program results are non-additive. For example, some evidence exists that when direct control is placed on air conditioning, consumers lower their thermostats in order to maintain comfort levels. This action would increase loads in the off-peak period by more than the load displaced from the peak period. As a result total requirements could be greater than would be experienced without the load control program. However, electricity production would be more efficient because the off-peak power could be produced more cheaply.

Recent research by EIA examined aggregate load shapes for changes over the period 1973 to 1982. The research found no identifiable systematic change in load shapes over the 10-year period at the Federal-Region level of aggregation. These aggregate results indicate that if load control programs had impacts on load shapes, these impacts were offset by other factors such as increased consumption of electricity during peak periods for uses that were not affected by load control programs. This study did not use data on individual utilities of which some may have effective load control programs that could affect load shapes.

QUESTIONS FROM SENATOR BUMPERS

ELECTRICITY SHORTAGES HEARING, JULY 25, 1985

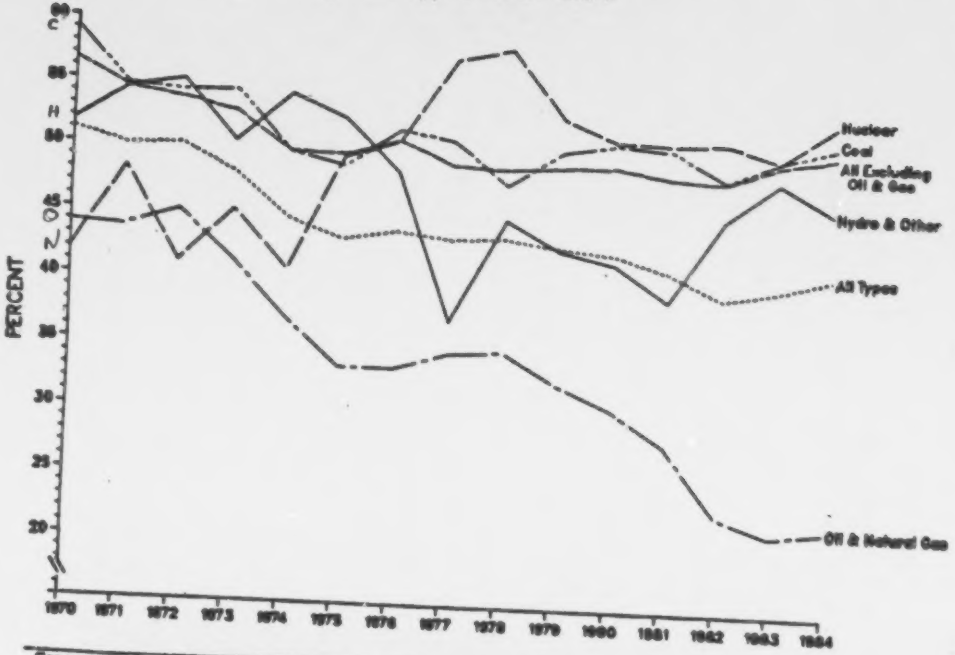
Question: Is all available capacity being used as efficiently as possible?

Answer: Because of the diversity of load, the optimal capacity mix consists of several types of capacity. The "base" load, which is the load that is demanded consistently 24-hours a day, is usually met by large fossil steam and nuclear plants, which have relatively high efficiencies, low operating costs, and are designed to run almost continuously. Turbines, which have quick start-up capability but relatively high operating costs are used to meet the peak, or highest load levels. Older and smaller steam units and combined cycle plants are used to meet the intermediate loads. Hydroelectric generation is primarily determined by the available water supply rather than the load characteristics and is generally used when available due to its very low operating costs. When hydroelectric units are limited by available stream flow, they are generally used in peaking mode.

The current utilization rates, or capacity factors, of coal-fired and nuclear plants are not as high as they have been in the past (See Figure). As shown in the Figure, the average capacity factor for all capacity types has

Figure.

Electric Utility Capacity Factors by Fuel Type, 1970–1984



Source: Coal capacity data are from the Energy Information Administration, Generating Unit Reference File. All other capacity data and generation data used to derive the capacity factors are from the Energy Information Administration, Annual Energy Review, 1984 (DOE/EIA-0384(84).

been declining in recent years. The decline in the capacity factor of oil- and gas-fired plants, which have the highest operating costs, has been much more dramatic than the corresponding decrease for coal-fired and nuclear units.

It would be difficult to characterize the decline in the overall capacity factor as a less efficient use of the available capacity, since many factors affect the utilization of generating units. For example, a particular unit may not be available for use because of a forced or planned outage. In addition, the demand levels may not require maximum utilization of baseload generating units. The utilization of the most economical units can also be affected by transmission constraints or the availability of less expensive purchased power.

QUESTIONS FROM SENATOR BUMPERS

ELECTRICITY SHORTAGES HEARING, JULY 25, 1985

Question:	Are availability ratios as high as they should be?
Answer:	Although the Energy Information Administration (EIA) does not collect data on electric utility availability factors, the North American Electric Reliability Council (NERC) provides information about equipment availability. The following table presents historical availability factors as reported by NERC, for large fossil steam units, grouped by size, and for nuclear units.

Table. Availability Factors for 1974-1983

	Year										
Plant Type	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	Average 1974-1983
Fossil Steam (200-574 megawatts)	81.8	79.3	79.1	79.7	80.3	78.9	80.0	80.1	80.5	81.1	80.1
Fossil Steam (575 megawatts and above)	75.6	74.5	73.5	71.8	73.9	75.0	76.4	78.1	77.5	78.6	75.8
Nuclear	68.1	73.5	70.5	73.7	77.2	68.2	68.8	70.3	64.7	65.3	69.6

Source: Equipment Availability Report 1974-1983, North American Electric Reliability Council.

The availability factors for the fossil steam units did not decline significantly during the 1974-1983 period.

In fact, during the 1980's, the availability factors for these units have been approximately equal to or above the average for the 10-year period. However, the availability factor for nuclear plants has declined considerably due to safety-related shutdowns after the accident at Three Mile Island.

QUESTIONS FROM SENATOR BUMPERS
ELECTRICITY SHORTAGES HEARING, JULY 25, 1985

Question: Are the utilities making all efficient economic coordination transactions?

Answer: Generally, it is impossible to determine if all efficient economic coordination transactions are being made. There is evidence, however, that suggests that a substantial volume of transactions do occur and that the volume of such transactions has been growing faster than either net generation or sales to ultimate customers. Among the investor-owned utilities between 1974 and 1983, the ratio of purchases to net generation increased from 15.6 to 18.7 percent and the ratio of sales for resale (that is, sales to other utilities) to net generation increased from 16.6 to 18.9 percent. At the same time, purchases as a fraction of sales to ultimate customers increased from 17.0 percent to 20.0 percent. That is, purchased power provided a growing share of sales to ultimate customers. Part of the increase in transactions comes from increased purchases from publicly owned utilities and from Canadian utilities.

A 1983 Energy Information Administration analysis titled Interutility Bulk Power Transactions (DOE/EIA-0418) (attached)* shows that utilities that depend on oil and gas capacity are more likely to buy power, while utilities that depend on coal capacity are more likely to sell power. Thus transactions are more likely to occur in the form of sales from regions with coal capacity to regions that depend on higher-cost oil and gas capacity. The analysis also shows that the stronger institutional arrangements for conducting economic coordination transactions (such as centrally dispatched power pools and energy brokering) are more likely to be found in regions that depend on higher-cost oil and gas capacity (for example, New England, New York, and Florida). This suggests that regions dependent on oil and gas capacity are attempting to make all of the economic transactions they can. Regions that depend on coal capacity, however, may not have as much incentive to engage in transactions because the gains from such transactions are lower. At the same time, the 1983 analysis shows that utilities in coal-dependent regions do engage in a large volume of coordination transactions.

Although there are probably opportunities for increasing economic coordination transactions, the critical factor is the ability of the transmission system to carry additional power transfers. Because of the benefits of coordination transactions in regions that depend on oil and gas capacity, the transmission systems in many such regions are currently being used to maximum reliable capacity. Increasing transactions within these regions or between these regions and regions with available coal (or hydroelectric) capacity generally depend on expanding the transmission system.

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*Committee Note.--Attachment has been retained in Committee files.

QUESTIONS FROM SENATOR BUMPERS

ELECTRICITY SHORTAGES HEARING, JULY 25, 1985

Question: Are there situations where it would be more cost effective to build transmission capacity rather than generation capacity?

Answer: There are situations where it is clearly more cost effective to build transmission capacity than generating capacity in the short run. If a utility (or region) depends on oil and gas capacity and there is available coal or hydroelectric capacity in adjacent utilities (or regions), then building transmission capacity to increase economic coordination transactions to displace generation from higher cost oil and gas capacity is probably going to be more cost effective than building new capacity to replace the existing oil and gas capacity. Utilities in Florida and Georgia are currently expanding transmission capacity to allow the Florida utilities to purchase additional power from coal-fired power plants in Georgia to displace oil and gas capacity. New York and New England are building additional transmission lines with Quebec and Ontario to import additional hydroelectric generation to displace oil capacity in these regions. Utilities in California and the Pacific Northwest (including the Bonneville Power Administration and the Western Area Power Administration) have agreed, this year, to construct a third 500-kilowatt AC transmission line between California and Oregon and upgrade existing lines over the next several years to increase the amount of hydroelectric generation that California utilities purchase to displace natural gas capacity. These improvements and expansions could represent about 3500 megawatts of additional capacity. To a certain extent, this type of transaction can continue in the future because of seasonal and daily load diversity. Growing demand in the selling region, however, would ultimately reduce the amount of electric power available for such transactions.

The same transmission lines and electric power purchases can also be used to meet load growth, instead of displacing oil and gas capacity. In this case, however, the cost effectiveness of new transmission capacity over new generating capacity is less clear-cut. Such transmission capacity may only postpone the requirement for new generating capacity. Growing electricity demand in the selling regions may eventually absorb the available capacity in these regions. Utilities, either in the selling region or in the purchasing region, would have to build new generating capacity to meet load growth -- although clearly it can be productive and serve utilities and consumers interests to postpone capacity expansion to a later date in some cases.

In addition, increased reliance on purchased power can in some cases reduce system reliability unless sufficient capacity is available both on transmission lines and in the purchaser's own generating capacity to meet contingencies (that is, transmission system or generator outages). Reliability is less of a constraint on displacement transactions because the displaced capacity is available for use in contingencies. When purchased power is used for meeting load requirements, both the purchaser and the seller must provide additional resources (both transmission and generating equipment) to meet reliability criteria.

This does not mean that purchased power from existing generating capacity cannot be used to meet load growth, especially over a limited time horizon, only that purchased power cannot be used indefinitely as a substitute for building new generating capacity.

CONGRESSIONAL BUDGET OFFICE
U.S. CONGRESS
WASHINGTON, D.C. 20515

Rudolph G. Penner
Director

September 9, 1985

MEMORANDUM

TO: Ms. Gerry Hardy
Assistant Calendar Clerk
Committee on Energy and Natural Resources

FROM: David L. Bodde Dave
Assistant Director
Natural Resources and Commerce

SUBJECT: Response to Questions from Senator Bumpers

Attached are my responses to the questions that Senator Bumpers posed to members of the first Panel in the Hearing of July 25, 1985.

If I can be of further assistance, please call (226-2946).

Enclosure

Q. What load control programs can be implemented in a 3 to 5 year period? What amount of capacity can they be expected to save by the mid-1990s?

A. Two methods of moderating peak demands--direct load control and time-of-day rates--are generally used by U.S. utilities. Direct load control uses automatic on-off switches to shed residential water heater and air conditioning loads during peak periods. Time-of-day rates rely on higher prices for electricity during peak periods to induce consumers to shift their consumption of electricity away from these periods. Expansion of these load management tools are less constrained by time or technological feasibility than by the costs of installing load management equipment and inducing consumers to participate.

Potential peak load reductions from existing and planned load management programs are considerable. A 1983 study estimates that about 27,000 megawatts of generating capacity (roughly equivalent to 27 large nuclear generating stations) that would have been needed by 1992 do not have to be built because of the conservation and load management programs now in place. 1/ The potential contribution of future load management remains great, perhaps an order of magnitude above its present contribution, because less than 1 percent of the current residential load is subject to such techniques. This could help displace the need for new generation in many service areas. However, the amount displaced is likely to vary widely from location to location. Many of these issues are discussed in greater detail in the recent OTA report, New Electric Power Technologies for the 1990s.

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1. See Investor Responsibility Research Center, Generating Energy Alternatives: Conservation, Load Management and Renewable Energy at America's Electric Utilities, (1983), cited in Office of Technology Assessment, New Electric Power Technologies for the 1990s, (1985).

Q. Is all available capacity being used as efficiently as possible? Are the utilities making all efficient economic coordination transactions?

A. Within the existing power pool network, utilities attempt to use capacity as efficiently as possible. All power pools attempt to dispatch power on a "least cost" basis according to current demand profiles. However, the interplay of various state and federal regulations can lead to some inefficient exchanges of wholesale power. For example, the pricing of electricity at average rather than marginal cost can, under some circumstances, lead to the displacement of low-cost power by higher cost power. The Federal Energy Regulatory Commission is considering this and other sources of inefficiency in its Notices of Inquiry of May 30 and June 28, 1985.

The net savings achievable through eliminating current inefficiencies could equal approximately 1 to 2 percent of total electric revenues, or 2 to 4 percent of operations and maintenance costs for generation. (See Federal Energy Regulatory Commission, Power Pooling in the United States, 1981; and Edison Electric Institute, Statistical Yearbook, 1981.)

Improvements to the existing power pooling network also could increase transmission efficiency, and could be cheaper in some cases than building new generation in power-short regions. However, many institutional and some financial constraints stand in the way of making such improvements soon. (See answer to follow-up question on the cost-effectiveness of building transmission capacity versus new generation capacity.)

Q. Are availability ratios as high as they should be?

A. There is always room for improvement in powerplant availability, however, availability ratios for recent periods differ by age, type, and size of generating units. Such differences in the composition of generating units make it difficult to determine what aggregate "target ratios" should be.

Over the last decade, fossil steam generating plants averaged between 75.8 and 80.1 percent availability. (See Table.) Smaller units (200-574 megawatts Mw) demonstrated higher availability ratios, than larger units (575 Mw and above). Nuclear units manifested a slightly lower availability ratio, 69.6 percent over the same period. No prominent trends are observed is fossil steam generation availability ratios, but nuclear plant availability ratios rose to a peak in 1978 with 77.2 percent availability, only to decline to 65.3 percent by 1983. During fiscal 1984, nuclear availability rose slightly to 68 percent. (U.S. Nuclear Regulatory Commission, Licensed Operating Reactors Status Summary Report, NUREG-0020, Vol. 9, No. 1, January, 1985.)

TABLE. AVAILABILITY FACTORS FOR 1974-1983

Plant Type	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	Average 1974-1983
Fossil Steam (200-574 megawatts)	81.8	79.3	79.1	79.7	80.3	78.9	80.0	80.1	80.5	81.1	80.1
Fossil Steam (575 megawatts and above)	75.6	74.5	73.5	71.8	73.9	75.0	76.4	78.1	77.5	78.6	75.8
Nuclear	68.1	73.5	70.5	73.7	77.2	68.2	68.8	70.3	64.7	65.3	69.6

SOURCE: Equipment Availability Report 1974-1983, North American Electric Reliability Council.

Q. Are there situations where it would be more cost effective to build transmission capacity rather than generation capacity?

A. Yes, the long lead times for new plant construction coupled with load growth uncertainty can create a situation in which building additional transmission capacity may be more cost effective than building generation capacity. "Transmission capacity" includes wheeling (transmission services provided by a utility to deliver power generated outside its own system to the system of another utility), improved intra-power pool wheeling, and hook-ups of co-generator-capable plants.

Excess capacity in some regions with relatively low marginal cost suggests that such transmission capacity could displace higher cost generation elsewhere, such areas would include parts of the Pacific Northwest and California, the Southwest and parts of California, Canada and the New England region, and New York, Georgia and Florida. (See Bauer, D. "An Investor-Owned Utility Perspective on Inter-System Energy Transfers and Wheeling Issues," Edison Electric Institute, November, 1984.)

Several difficulties must be overcome, however, before such investment takes place. First, many bottlenecks have occurred concerning rights-of-way, local regulatory, pricing and licensing of high-voltage transmission. These have led to costly delays and, questions concerning the eventual rates of return and cost-recovery of transmission capacity. Second, legal and contractual issues arise concerning third-party wheeling, cogeneration, and inter-utility, utility, state and federal regulatory commission planning and financing of transmission facilities. Third, the desirability of importing electricity from Canada must be addressed at a federal level.

It is likely, however, that expanding the wholesale power market is economically desirable despite these three problems. The Federal Energy Regulatory Commission is now investigating ways to increase the economic exchange of wholesale power in its Notices of Inquiry dated May 30 and June 28, 1985. (See also Joskow P. and R. Schmalensee, Markets for Power, MIT Press, 1983; Federal Energy Regulatory Commission, Power Pooling in the United States, FERC-0049, 1981; American Public Power Association, "Electric Transmission in the U.S.: Problems and Solutions," July, 1985.)

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August 20, 1985

SENATE CO
ENERGY AND NAT
AUG 23
WASHINGTON,

The Honorable James A. McClure
Chairman
Committee on Energy and Natural Resources
United States Senate
Suite 358 Dirkson Senate Office Building
Washington, DC 20510

Dear Mr. Chairman:

Thank you for the follow-up questions regarding OTA's testimony before the Energy and Natural Resources Committee on July 25, 1985. Enclosed is our response to those questions. If you, any Member of the Committee, or the Committee staff have any additional questions or would like elaboration on our response we would be pleased to provide further information. In addition, many aspects of the follow-up questions are discussed in more detail in our recently released assessment, New Electric Power Technologies: Problems and Prospects for the 1990's. I believe many of the Committee staff already have copies of this report, but I have enclosed another for your reference.

Thank you again from both Dr. Rowberg and myself for the opportunity to testify on this important issue before your Committee.

Sincerely,

Peter D. Blair

Peter D. Blair
Project Director

PDB/apl
enclosure:
full report
summary
report brief

R. Rowberg 7/25/85 Testimony Questions

What load control programs can be implemented in a 3 to 5 year period? What amount of capacity can they be expected to save by the mid-1990s?

Direct load control programs, i.e., those controlled by the utility, in residential applications appear to offer the most promise within 3 to 5 years. This is because the technologies for such systems are more mature than those for more advanced local and distributed systems. The more advanced systems will eventually permit more interaction with the customer in controlling loads, thereby increasing the likelihood of customer acceptance. While residential loads comprise only a third of total electricity demand, many commercial and industrial load management programs are already in place so that the prospects for additional control in these sectors are less promising than in residential sector. The impact on generating capacity requirements of direct load control programs depends on the continued success of experimentation by utilities to resolve operational uncertainties; the refinement of load management equipment and techniques including adequate demonstration of communications and load control systems; development of incentive rate structures; and a better understanding of customer acceptance.

At present about 1.5 million points are controlled (see table 1), which is only a small fraction of the number of residential loads that could be controlled (probably less than one percent). A much larger potential exists in every region of the country, particularly in the South where residential electricity demand is high and there are a large number of all-electric homes. A recent Electric Power Research Institute survey of the stated intentions of utilities indicates that if currently planned load control programs are implemented, at least 5 million new points may be controlled by 1990. Others suggest that as many as 8 million points will be controlled by 1990 and 20 million points by 1995.

If load management programs are effective, they can contribute to reducing future demand uncertainty if the saturation and use of load management devices can be accurately predicted. If such predictions are not possible, however, then increased load management could actually increase demand uncertainty. Commitments to initiate load management systems will also depend on the nature of a utility's demand patterns and capacity mix, the attitudes of utility decisionmakers, and on public utility commission actions. The degree of public utility commission support, in particular, is likely to be very important over the next decade.

While the potential magnitude of the impact of load control on generating capacity requirements is difficult to gauge, evidence from current load management efforts indicates that the impact could be quite sizable. If, for example, one air conditioner in each of 5 million homes were controlled, and if an average peak load reduction of 1 KWe were obtained, a peak load reduction of about 5,000 MWe would result. Note that nearly 50 million homes have air-conditioning and that many of these have more than one air conditioner. Also residential air conditioning represents only one of many loads which could be controlled (see table 2).

Is all available capacity being used as efficiently as possible? Are availability ratios as high as they should be? Are the utilities making all efficient economic coordination transactions? Are there situations where it would be more cost effective to build transmission capacity rather than generation capacity?

Overall generating capacity factors, nationally, declined substantially from the early 1970's through 1984 -- from over 50 percent to approximately 42 percent. Much of this decline came about as utilities replaced costly oil- and gas-fired generation with coal and nuclear plants, relegating the former to intermediate and peaking duty cycles. Some of the decline can also be attributed to overbuilding during that decade. Currently, improvement in availability of existing coal and nuclear plants is clearly possible and is indeed an industry objective over the next decade as part of a strategy of avoiding commitments to new capacity. For coal, improvements from the current 50 percent to 55 percent and for nuclear from 55 to 60 percent may be possible. Considerable increases in capacity utilization of oil- and gas-fired generation are also possible and likely over this period but at the cost of increased consumption of those fuels.

R. Rowberg 7/25/85 Testimony Questions

It appears that existing interutility and interregional transmission capabilities are being nearly fully utilized in the United States. Hence, the prospects for large increases in bulk power purchases among utilities using existing transmission capabilities will be limited. With additional transmission, however, it is likely that more efficient use of existing generating capacity would result. Some regions, such as portions of the West and Midwest, are continuing to expand generation and transmission facilities in anticipation of serving the bulk power markets. In addition, major transmission projects are underway in New York, New England, the upper Midwest, and the Pacific Northwest to allow these regions to purchase lower cost hydroelectric power generated in Canada from existing and proposed facilities. Finally, while new transmission is a costly undertaking, there is evidence at least in California and Florida that added transmission capacity is cheaper than coventional generation.

Table 1 .—Load Control: Appliances and Sectors Controlled in 1983 Under Utility-Sponsored Load Control Programs

Appliance/sector	Number of points controlled
Electric water heaters:	
All sectors	648,437
Residential	643,910
Commercial	4,527
Air-conditioners:	
All sectors	515,252
Residential	491,675
Commercial	23,577
Irrigation pumps:	
All sectors	14,261
Space heating systems:	
All sectors	50,238
Residential	48,546
Commercial	1,692
Swimming pool pumps:	
Residential	258,993
Miscellaneous:	
All sectors	13,710
Residential	13,088
Commercial	34
Industrial	588
All appliances:	
All sectors	1,500,[illegible]91 (100%)
Residential	1,456,[illegible]2 (97%)
Commercial	29,830 (2%)
Industrial	588 (negligible)
Agricultural	14,260 (1%)

SOURCE: Synergic Resources Corp., *1983 Survey of Utility End-Use Projects* (Palo Alto, CA: Electric Power Research Institute, May 1984), EPRI EM-3529.

Table 2 .—Major Uses of Purchased Electricity in the United States, 1983

Sector	Application	Billions of kWh (estimated)	Percent of total U.S. purchased electricity
Industrial	Machine drive	539	25
Commercial	Air-conditioning	231	11
Commercial	Light	220	10
Residential	Air-conditioning	111	5
Industrial	Electrolysis	103	5
Residential	Water heating	97	4
Industrial	Process heat	97	4
Residential	Space heat	70	3
Commercial	Water heating	59	3
Industrial	Light	47	2
Commercial	Space heat	29	1
Total		1,603	74

SOURCES: **Industrial:** The breakdown for industrial electricity use was obtained from table 1-10 in Pradeep C. Gupta and Ahmad Faruqui, "EPRI Perspective on Industrial Electricity Use," *Proceedings: Forecasting the Impact of Industrial Structural Change on U.S. Electricity Demand*, Battelle Memorial Institute, Columbus Laboratories (ed.) (Palo Alto, CA: Electric Power Research Institute, 1984), EPRI EA-3816, pp. 1-1 through 1-17. The percentage breakdown provided in the article was for 1980. It was assumed in the above calculations that the breakdown in 1980 was the same as that in 1983. These percentages were applied to the Department of Energy estimates of industrial purchases of electrical power, see U.S. Department of Energy, Energy Information Administration, *Energy Conservation Indicators 1983 Annual Report* (Washington, DC: U.S. Government Printing Office, 1984), DOE/EIA-0441, table 33.

Commercial: The breakdown for commercial energy consumption was obtained from Oak Ridge National Laboratory's *A User's Guide to the ORNL Commercial End Use Model* (Oak Ridge, TN: ORNL, 1983). It was assumed in the above calculations that the breakdown provided by ORNL was the same as that which characterized the commercial sector in 1983. These percentages were applied to the DOE estimates of industrial purchases of electrical power, as provided in table 34 of the *Energy Conservation Indicators 1983 Annual Report*, op. cit., 1984.

Residential: The breakdown for residential energy consumption was obtained from an estimate provided from U.S. Department of Energy, Energy Information Administration, *Annual Energy Outlook 1984* (Washington, DC: U.S. Government Printing Office, 1984), DOE/EIA-0383 (84), table A6. The breakdown was applied to the 1983 estimate of residential electricity purchases, as provided in table 11 of the *Energy Conservation Indicators 1983 Annual Report*, op. cit., 1984.

APPENDIX III

Additional Material Submitted for the Record

Frank H. Murkowski

STATEMENT OF SENATOR FRANK H. MURKOWSKI
ON THE
POTENTIAL FOR ELECTRICAL POWER SHORTAGES
BEFORE THE
SENATE COMMITTEE ON ENERGY AND NATURAL RESOURCES
JULY 25, 1985

MR. CHAIRMAN, I AM PLEASED TO OFFER SOME BRIEF REMARKS AT THESE VERY IMPORTANT HEARINGS AND COMMEND YOU FOR HOLDING THEM. ENSURING AN ADEQUATE FUTURE SUPPLY OF ELECTRICAL ENERGY IN THE UNITED STATES IS A SERIOUS AND COMPLEX PROBLEM.

IT IS A SERIOUS PROBLEM BECAUSE OF THE EXTREME CONSEQUENCES WHICH CAN RESULT FROM A SHORTAGE OF ELECTRICITY. THE PROSPECT OF FACTORIES, OFFICE BUILDINGS AND SCHOOLS BEING CLOSED FOR LACK OF ELECTRICITY IS ONE THAT NO ONE REALLY CARES TO CONTEMPLATE.

THE PROBLEM IS COMPLEX BECAUSE OF THE MANY ELEMENTS OF THE ELECTRICAL ENERGY INDUSTRY. GENERATING UTILITIES HAVE BECOME EXTRAORDINARILY CAUTIOUS IN COMMITTING TO NEW GENERATING CAPACITY: TO THE POINT OF PREFERRING THE POSSIBILITY OF SHORTAGES TO THE EXISTENCE OF TOO MUCH EXCESS CAPACITY. THE REASON FOR THIS POLICY IS UNDERSTANDABLE. THEY RELIED UPON FORECASTS FOR INCREASED DEMAND THAT PROVED TO BE OVERLY OPTIMISTIC. CONSUMERS, IN RESPONSE TO HIGHER ENERGY COSTS, TOOK ENERGY CONSERVATION SERIOUSLY AND REDUCED THEIR USES OF POWER INSTEAD OF INCREASING THEM. WHEN UTILITIES SOUGHT TO PASS ON THE COSTS OF THEIR RELIANCE ON THE FORECASTS THE CONSUMERS OF ELECTRICAL POWER REVOLTED. UTILITY REGULATORY BODIES WERE CAUGHT IN THE MIDDLE AND IN MOST CASES BEGAN TO SIDE WITH THE CONSUMERS; THE RESULT WAS TO MAKE UTILITY MANAGERS VERY HESITANT TO BUILD NEW CAPACITY WHICH THEY WERE NOT ABSOLUTELY SURE WOULD BE USED AND USEFUL.

IT DOES NO GOOD WHATSOEVER TO ATTEMPT TO LAY BLAME FOR THIS SITUATION ON ONE PARTY OR ANOTHER. RATHER WE SHOULD BE LEARNING FROM OUR MISTAKES OF THE PAST WAYS TO AVOID SIMILAR MISTAKES IN THE FUTURE. WE CAN DO THIS BY RECOGNIZING ALL OF THE PLAYERS---THE UTILITIES, THE CONSUMERS, THE REGULATORS, THE FORECASTERS, AND THE CO-GENERATORS---AND ALL OF THE OPTIONS---NEW FOSSIL FUEL OR NUCLEAR GENERATING CAPACITY, SMALL ALTERNATIVE GENERATING CAPACITY, CONSERVATION AND CO-GENERATION---AND REALIZING THAT THEY ALL HAVE A ROLE TO PLAY IN GUARANTEEING THAT WE DO NOT SUFFER FROM ELECTRICAL ENERGY SHORTAGES IN THE COMING DECADE.

MR. CHAIRMAN, I HAVE LONG BEEN AN ADVOCATE OF ESTABLISHING A NATIONAL ENERGY POLICY. THE SITUATION FACING OUR ELECTRICAL POWER INDUSTRY SERVES AS ANOTHER EXAMPLE OF THE NEED FOR SUCH A

POLICY. IT IS ONE THING TO RECOGNIZE THE PLAYERS AND THE OPTIONS IN THE ELECTRICAL ENERGY BUSINESS; BUT QUITE ANOTHER TO DETERMINE WHO IS TO TAKE THE LEAD IN BRINGING THEM ALL TOGETHER AND PROVIDING A FRAMEWORK WITHIN WHICH TO BEGIN TO SOLVE THE SERIOUS PROBLEMS FACING THE INDUSTRY. YOU ARE TO BE COMMENDED FOR BRINGING MOST OF THE PLAYERS TOGETHER HERE TO AIR THE NATURE OF THE PROBLEMS THEY FACE. THAT IS AN IMPORTANT FIRST STEP. HOWEVER, WITHOUT SOME TYPE OF NATIONAL POLICY TO GUIDE THE DELIBERATIONS ON THOSE PROBLEMS AND THE CHOICE OF A CORRECT MIX OF THE OPTIONS I AM AFRAID THAT THE SOLUTIONS AGREED UPON MAY PROVE TO BE SHORT SIGHTED REMEDIES WHICH EVENTUALLY LEAD TO ANOTHER CRISIS FURTHER DOWN THE ROAD.

THANK YOU MR. CHAIRMAN.

STATEMENT OF SENATOR DAVID PRYOR

BEFORE THE SENATE ENERGY COMMITTEE

JULY 23, 1985

MR. PRYOR. Mr. Chairman, I'm pleased to submit testimony to the committee today on utility regulation and the future demand for electricity in this country. I commend you for holding these hearings.

My comments today will largely focus on one issue, which is of monumental importance to all businesses and individuals in the State of Arkansas. It deals with an allocation of costs of a nuclear facility (Grand Gulf) which will have a devastating affect on the ratepayers of the State of Arkansas. Not only is this decision wrong, Mr. Chairman, as I'll point out later, but I believe it should be looked at by the committee as you consider S. 1149, a bill Senator Bumpers and I introduced on May 16th of this year. It deals with the regulatory process when utility rates are involved, and the local public utility regulatory body did not approve the construction.

S. 1149 will address a situation currently facing Arkansas ratepayers, Mr. Chairman. They are being asked to pay for a portion of the costs of the construction of a nuclear facility, and Arkansans neither need nor want any of the power produced by the plant. While this bill is designed to deal with this problem, Mr. Chairman, other states could find themselves in similar situations. As I'll explain in a moment, the state regulatory process (which protects the ratepayers in that particular state) can be sidestepped, and that's exactly what happened in the State of Arkansas.

Let me briefly explain to my colleagues the situation now facing the ratepayers of the State of Arkansas.

In the early 1970's Middle South Energy, Inc. (a subsidiary of Middle South Utility established solely for the construction of nuclear plants) began construction of two nuclear plants - Grand Gulf I and Grand Gulf II. Middle South Utility is the parent and has four operating companies - Arkansas Power and Light (AP&L), Mississippi Power and Light (MP&L), Louisiana Power and Light (LP&L), and New Orleans Public Service, Inc. (NOPSI).

The two nuclear power plants were to be constructed in Port Gibson, Mississippi. At the time construction was begun, both plants were estimated to cost $1.2 billion. Today, $3.6 billion has been spent. Grand Gulf I is now completed, although not in full operation, and Grand Gulf II is about one-third complete. Under the original plan, Middle South Energy would sell the energy produced to each of the operating companies. Since the power would be sold across state lines, Mr. Chairman, rates would be determined by the Federal Energy Regulatory Commission (FERC), and not by the state utility regulatory commission.

When the decision was made to construct these two nuclear plants, Mr. Chairman, agreements were made by the Middle South operating companies on how to share in the costs in the event the plants never became operational. AP&L was assigned a relatively small percentage.

If, however, the plants became opertional it was assumed that each of the operating companies would pay a "floating percentage" depending upon the amount of power used. In fact, in 1977 officials of Middle South testified before the Arkansas Public Service Commission and stated that Arkansas ratepayers wouldn't have to share in the costs of the plant if we didn't use any of the power generated. It was then assumed by AP&L, and state authorities, that unless Arkansas energy needs required it, no power or cost allocation would accrue to the citizens of Arkansas. In keeping with this arrangement and later estimates, Middle South Utility in 1981 assigned a fixed percentage of the power from the Grand Gulf units to its four operating companies. In keeping with previous agreements, however, AP&L wasn't given any portion since Arkansas didn't need any of the power, but the percentage allocations were made to the other three companies. It's important to keep in mind, that during this time when the parent company, MSU, and its construction subsidiary, MSE, were entering into agreements with the four operating companies on how to allocate costs and power, the utility regulatory commissions were totally with authority to intervene.

The fixed allocations (under which AP&L was given a zero share in Grand Gulf) were held invalid by an Administrative Law Judge of the FERC in 1984. His ruling was that AP&L, and ultimately the ratepayers of the State of Arkansas, were responsible for about one-third of the cost of the Grand Gulf unit. Later, in June of this year, the full FERC ruled that Arkansas Power and Light Company (and therefore, the ratepayers of Arkansas) are responsible for 36% of the cost of Grand Gulf. This decision, unless changed, will have a devastating effect on the entire economy of the State of Arkansas, and it will have gone into effect without the Public Service Commission of the State of Arkansas from ever having passed on the rates to be imposed on the citizens of the state.

Mr. Chairman, late last year my colleague from Arkansas, Mr. Bumpers, held a hearing in Little Rock, Arkansas, on how this decision would affect businesses and farmers in our state. The overwhelming sentiment of those who testified or submitted statements for the record was that such a precipitous increase in utility costs would have an utterly devastating impact on the total Arkansas economy. The timber industry, cattlemen, milk producers, independent grocers, rice, soybean and cotton farmers, and manufacturers of all sizes testified that their operations would be severely hurt if AP&L is forced to take an allocation of Grand Gulf.

During the last Congress, Senator Bumpers and I introduced legislation that would have amended the Federal Power Act by prohibiting the FERC's authority to order public utilities to purchase power or share in the construction costs for an generating facility the title of which is held by some other entity.

The bill we've introduced is different in this respect -- it does not prohibit the FERC from ordering an associate company of a public utility holding company to purchase power from another associate company. But, it does require that if such a purchase occurs, and if the rates are based in any way on the allocation of costs for a new generating unit, these rates will be subject to the jurisdiction of any state's utility regulatory agency, which has not approved construction of the new generating unit. It seems only fair, Mr. Chairman, that state utility regulatory agencies, who had no say over the decision to construct the facility, should have some authority to review rates that will be imposed on the ratepayers of that state as a result of the costs of construction of the new unit.

This is not an overly complex bill, but it is one that should prevent the circumvention of a regulatory commission established to ensure fair and reasonable utility rates. The

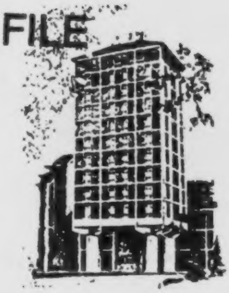
Grand Gulf case shows very clearly why this bill is needed. Arkansas ratepayers could be saddled with much higher electric rates based on the costs of the construction of a nuclear facility in another state, without the Arkansas regulators ever having had any authority to review the rates. The bill we've introduced would give the state's some authority in this area, and would restore some balance between state and federal regulation to this very critical and important area.

Again, Mr. Chairman, I appreciate your holding these hearings and I appreciate having the opportunity comment on these matters.

OFFICIAL COMMITTEE FILE

UNIVERSITY OF COLORADO AT BOULDER
CAMPUS BOX 390
BOULDER, COLORADO 80309
PHONE: (303) 492-6952

DEPARTMENT OF PHYSICS



JUL 22 '85

SENATE COMMITTEE ON
ENERGY AND NATURAL RESOURCES
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July 17, 1985

Hon. James McClure
United States Senate
Washington, D.C. 20510

Dear Senator McClure,

Science magazine (July 19, 1985, pg. 249) reported that your Energy and Natural Resource Committee will hold public hearings July 23-25 on the questions of the present capacity of the electric generating industry and on the plans for the growth for this capacity.

I would appreciate it very much if the enclosed Letter, which has been submitted to the Editor of Science magazine, could be made a part of the record of your Committee's hearing.

Sincerely yours,

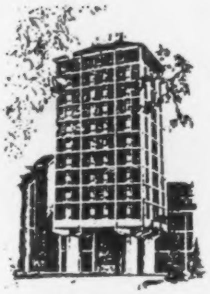
Albert A. Bartlett

Albert A. Bartlett
Professor

AAB/mk

UNIVERSITY OF COLORADO AT BOULDER
CAMPUS BOX 390
BOULDER, COLORADO 80309
PHONE: (303) 492-6952

DEPARTMENT OF PHYSICS



July 17, 1985

Letter to the Editor
Science Magazine
American Association for the Advancement of Science
1515 Massachusetts Ave NW
Washington, DC 20005

Dear Sirs:

The "Electric Industry's Dilemma" (Science, 229, 248, 1985) becomes even more realistic when one considers the costs of constructing the projected new electric generating plants. These costs range from $1 a watt for conventional generating plants to the $4 a watt quoted in your article for nuclear plants. The present U.S. generating capacity is 5.6×10^{11} W, so an annual growth rate of 1% would call for an initial annual construction rate of 5.6×10^{9} W/yr. The annual cost of this construction would then lie in the range from $\$5.6\times10^{9}$ to $\$2.2\times10^{10}$ which is an annual cost of between $23 to $93 per person for every man, woman, and child in the U.S. The following table shows the annual costs in dollars per person for each of the 2.4×10^{8} people in the U.S. for the annual growth rates of 2%, 2.5%, and 4% shown in the graph in the article.

Table 1

Annual Demand	Power Plant	Construction Costs
Growth Rate	$1/W	$ 4/W
1%	23	93
2%	47	187
2.5%	58	233
4%	93	373

The table shows that a 2% annual growth rate of low-cost electric generating plants ($1/W) would cost every man, woman, and child $47 a year ($3.90 a month) or about $16 a month for a family of four! These costs are in addition to the present electric utility bills!

These figures show why we are not experiencing the 7% annual growth rates of electric generating capacity of two decades ago and why the annual growth rate of electric generating capacity in the U.S. will probably be less than 2% through the coming decade.

Sincerely yours,

Albert A. Bartlett
Department of Physics
University of Colorado
Boulder, CO 80309-0390

AAB/lf

U.S. ELECTRIC UTILITY INDUSTRY

OUTLOOK TO THE YEAR 2000

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380 Madison Ave., 12th Floor, New York, NY 10017
Tel. (212) 309-5300

Frederick W. Deming
Senior Vice President & Economist

A sound electric utility sector is essential for a healthy economy. The changes sweeping utility markets in recent years have posed difficulties for many electric companies, underscoring how important a reliable power system is to all walks of American life.

In the past year, the Economic Research Department has attempted to study the issues and evaluate the industry's prospects. I invite you to read the analysis and share in our conclusions.

Frederick W. Deming

Frederick W. Deming
Senior Vice President & Economist

U.S. ELECTRIC UTILITY INDUSTRY
OUTLOOK TO THE YEAR 2000

by
Constantine G. Soras

Global Industries Unit
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February 1984

CHEMICALBANK

EXECUTIVE SUMMARY

In the last ten years U.S. electric utility companies have suffered market disruptions and financial distress never experienced before. Some problems will go on for several more years. But our research shows that by the second half of this decade *the utility sector in general will be enjoying more balanced markets and significantly stronger finances,* meaning improved credit worthiness. By 1987-88 the utility industry will be in a much stronger financial position, poised to renew its investment program. Thus, investor-owned utilities are expected to *invest $613 billion in the 1990s,* twice the $311 billion we estimate for this decade.

Our principal research findings include the following:

- Electricity demand to the end of the century will grow at a trend rate of 2.6 percent per year, down from 6 percent before 1980 but enough to gradually clear the present capacity surplus by 1992.
- By around 1986, companies will start placing orders for new capacity at the rate of 12 million kW. Annual orders will edge up to 19 million kW by the end of this decade and average about 23 million kW during the 1990s.
- Net capacity additions in the 1990s will be 10 percent greater than in the 1980s; however, total new capacity will be 42 percent greater than in the 1980s because of replacement needs.
- Environmental concerns and substandard performance have effectively eliminated any new orders for nuclear plants over the forecast horizon. Almost all capacity additions in the 1990s will be coal-fired.
- The industry's financial position should improve steadily in this decade and will be strongest in the second half. In the 1990s it will earn a competitive return on capital.
- New policies will emerge to address the acid rain issue, forcing extra pollution control outlays by 1986. The additional spending, about $20 billion, will not harm the industry's financial health.

In summary, it is our conclusion that conditions for the majority of electric utility companies are improving. This conclusion may not hold true for all companies, however, particularly those entrammeled in costly nuclear plant construction. Some of these may continue to suffer financial pressures, perhaps even serious enough to affect the confidence of financial markets. However, we believe that this situation, while of deep concern to certain companies and regions, will not permanently damage the overall industry's access to capital markets.

OVERVIEW

The pattern of U.S. energy demand has changed radically since the oil embargo of 1973 and the second oil shock of 1979. Electric power sales grew rapidly from 1960 to 1973, at 7.3 percent per year. Growth slowed to 3.0 percent a year from 1973 to 1981; and sales actually fell in 1982, the first slippage since 1945. From 1960 to 1981 electric demand outgrew overall economic activity as gauged by real gross national product (GNP)—by 1.7 times in the pre-embargo period and by 1.2 times in the post-1973 period. By contrast, expansion of non-electric energy demand was only about 80 percent of GNP growth between 1960 and 1973 and has been on a downtrend since 1973, even though GNP has risen at 2.4 percent a year on average since 1973. Energy prices registered dramatic increases after the 1973 oil embargo: in 1980 the real price of energy in aggregate was twice as high as in 1960. By contrast, the real price of electricity in 1980 was about the same as in 1960, although price movements differed among customer categories and regions.

A utility's franchise requires that reliable service be provided on demand. To do so, net generating capability must exceed the maximum load on the power system. Since the time between planning an electric power plant and on-line operation runs about 6-8 years for coal-fired installations and 12-14 years for nuclear ones, utilities must correctly project future demand and accordingly place orders for new capacity ahead of time. The unanticipated break in the growth of demand since 1973 has left utilities with excess capacity, undesirable capacity mix, and burdensome construction programs. These problems—together with high inflation, soaring fuel costs, sharp increases in the cost of financing, far longer construction lead times, and the reluctance of state commissions to grant sufficient and timely rate relief—have undermined the financial position of many utility companies.

The critical question is whether the industry's financial position will continue to deteriorate or will improve in the short-to-medium term. Further deterioration would force the industry to supply power only at high cost and, more importantly, would jeopardize the reliability of service. Conversely, stronger finances would allow the industry to undertake the capital spending required for adequate capacity, guaranteeing reliable service while affording utilities a competitive return on investment.

We visited large utilities around the country to discuss the issues. We also reviewed leading research studies. We then built an econometric model to deal with the questions of interest. In this study we analyze the demand for electricity by residential, commercial, industrial, and other end users to understand the underlying changes in these markets. After forecasting demand, we determine the amount of new capacity required and sort out future capacity by fuel inputs, ascertaining total fuel requirements. Finally, we look at capital spending requirements and financing needs.

Our analysis finds that the decline in electricity demand in 1982 is explained by the severe drop in homebuilding and industrial production and by mild summer weather. Demand for electricity will resume its growth, up 2.6 percent a year on average in 1981-90 and 2.5 percent per annum in the 1991-2000 period. These rates are far smaller than the 4.4 percent seen in 1971-80 and the 7.4 percent in 1961-70. Slower growth reflects demographic trends, changes in the stock and mix of appliances, programs to promote insulation, and new energy-efficient residential and commercial structures. Industrial plants and processes will also be significantly more efficient, while production itself will be growing more slowly.

Electric companies will pursue capital conservation policies for some time to come. This means greater emphasis on improvements in the control of the nationwide power grid, higher utilization rates for oil- and gas-fired plants, and enhanced plant capability through rigorous maintenance. Given existing construction programs, capacity could be stretched to provide reliable supply through 1993 at the latest. Thereafter, new plants must come on line to avoid blackouts, brownouts and excessive reliance on expensive and uncertain supplies of oil and gas for baseload generation. In light of long lead times for construction, new orders will start arriving around 1986.

Given the cost and availability of fuel, only coal and nuclear plants are feasible choices for significant new power supplies. The best hydroelectric sites have been exploited. Oil-based generating costs are prohibitive. Limited reserves of natural gas and the prospect of price decontrol make much new gas-based capacity unlikely. Such other sources as geothermal and solar offer minor potential, no more than 12 million kW in all by the end of the century. Imports of electricity will continue to be a minor source of supply, in the longer term not to exceed 2 percent of total U.S. consumption.

Almost all new orders will be for coal-fired plants. Mined at home, coal supplies are both secure and ample—good for 340 years at current rates of production. Problems with public health and safety, costs and operating performance militate against new orders for nuclear units in this period.

Current-dollar capital spending by *investor-owned* electric utilities will run at about $33 billion per year through 1986 and then edge down as most projects under construction are finished. Investment will climb slowly after 1988 and then proceed on a strong uptrend in the 1990s. Capital outlays in the 1980s will amount to $311.3 billion for 113 million kW of net capacity. For the 1990s required capital spending will total $613.3 billion for additions of 123.4 million kW and replacement of about 34 million kW.

The financial position of electric utilities should improve steadily as investment winds down and cash flow grows. The share of industry investment financed externally will drop from an estimated 43.5 percent in 1983 to around 15 percent in 1988. If current regulatory conditions prevail, investor-owned utilities' needs for external funds would be $97.1 billion for the 1981-90 period or 30.3 percent of total investment. For 1991-2000, funds from outside sources will amount to $230.5 billion or 37.6 percent of total investment. As utility finances revive, however, regulators are likely to act on the acid rain issue and other problems in an environment of ever more coal-fired plants, adding an estimated $20 billion to pollution abatement outlays in the 1986-90 period; external needs would then be $117 billion for this decade.

RESIDENTIAL SECTOR DEMAND

Total residential demand for electricity is determined by the number of residential customers and average use per customer. The number of customers in the long term is a function of demographic trends, particularly household formations; in the short term, interest rates and economic activity affect homebuilding and, hence, new customers. Average power consumption depends on both the stock of electric appliances and their utilization.

The utilization of some appliances reflects weather conditions, thermostat settings and electricity prices. Air conditioners are likely to be run at full capacity when high temperatures exceed some critical level of comfort, while furnaces and space heaters are used intensively during severe cold weather. Higher electric rates tend to reduce consumption gradually through turnover in the stock of appliances as new, more energy-efficient models replace older designs. Similarly, various incentive programs to promote insulation will reduce the level of electricity consumption. We estimate that thus far in the process of adjustment to higher electricity bills since 1979, aggregate residential consumption has been reduced by 12 to 15 billion kWh or 1.6 to 2 percent of 1982 sales (729 billion kWh).

Besides intensity of use, changes in the stock of appliances per se and its composition affect power consumption. Appliances fall into two categories: those that are solely electric powered and those that use other fuels. Markets for some appliances in the first category have reached saturation; unit demand will generally reflect demographic trends and, therefore, will have little or no impact on power consumption per customer. Radios, televisions, refrigerators and irons reached market maturity by 1965; saturation for coffeemakers, toasters, and vacuum cleaners did not occur until the early 1970s. In other important cases, however, saturation has not yet occurred. In 1979, for example, only 55.5 percent of 79.4 million homes had air conditioners and just 43 percent had dishwashers. These markets offer considerable potential for growth in average use as determined primarily by demographics and income. Finally, the advent of totally new products will add to customer usage. In the second category of appliances, electricity competes with natural gas and LPG and sometimes with fuel oil. The principal areas of competition are space heating, water heating, and cooking. Growth in electricity demand for such applications will be determined by relative prices of fuels, the relative costs of new appliances by fuel type, regional differences in climate, and population shifts.

There is ample room for expansion of electric sales beyond that induced by customer base growth. In 1950, less than 1 percent of 43 million households used electricity as the primary space heating fuel. This share increased to 1.8 percent by 1960. Thereafter, growth accelerated, reaching 4.9 million households by 1970, 7.7 percent of all homes. The uptrend continued after 1973 but at a slower pace. Households using electricity for heat reached 14.2 million in 1980, or 17.7 percent of all units. By region, 27.8 percent of housing units in the South use electricity for heating, 20.8 percent in the West, 8.4 percent in the Northeast and only 7.5 in the North Central region. Since the South and West account for nearly 53 percent of the nation's housing units and only 25 percent of them are electrically heated, the home heating market is still far from saturation. On an annual basis, the typical electrically-heated unit consumes 55 million Btu's of power vs. 25 million Btu's on average for other homes; thus, gains in share for electric heat translate into large increases in electricity consumption.

For water heating 32.6 percent of all households use electricity. Natural gas is the preferred fuel with a 54.9 percent share; oil has 7.3 percent, liquified gas 4.1 percent, and one percent is ascribed to other sources. By region, 50.2 percent of the households in the South use electricity for water heating, whereas the proportion elsewhere is much smaller: 26.4 percent in the West, 24.5 percent in the North Central and 20 percent in the Northeast. Except for the Northeast, where 31.8 percent of the households use fuel oil, natural gas is the dominant fuel for water heating. For cooking electricity is the main fuel accounting for 54.6 percent of all households. Nearly 60 percent of the households in the West and South use electricity, 51 percent in the North Central and 44 percent in the Northeast. Natural gas and liquified gases are the principal alternatives.

The proportion of households with some form of air conditioning was 54.7 percent in 1981, indicating that on a national basis this market has a way to go before becoming saturated, although this may not be true for some locales. Over the period 1974-80 more than 73 percent of new construction had installed some form of air conditioning. If this trend were to continue, by the year 2000 the national average will still be below 65 percent.

As coal and nuclear energy replace oil and gas in generating electricity and as prices for natural gas (expected to be decontrolled by 1985) increase, we expect residential demand for electricity to grow at an average annual rate of 3.7 percent in the 1983-85 period, 3.7 percent in 1986-90, 2.7 percent in 1991-95 and 2.1 percent in 1996-2000 (Tables 1-2). Acceleration in 1983-85 reflects renewed growth of the housing stock after the 1980-82 home building slump. Also, real disposable income will grow faster over this period due to the expansion in the economy and the July, 1983, tax cut. The slowdown in the rate of growth to 2000 stems from the declining rate of growth in the housing stock, meaning smaller gains in new residential customers.

TABLE 1

ELECTRIC SALES BY END-USER
Residential(DR), Commercial(DC), Industrial(DI), Other(DO), Total

	(Billion kWh)					(Percent)				
	DR	**DC**	**DI**	**DO**	**Total**	**DR**	**DC**	**DI**	**DO**	**Total**
1960	196.4	114.8	344.8	27.2	683.2	28.7	16.8	50.5	4.0	100
1965	281.0	202.1	433.4	37.0	953.4	29.5	21.2	45.4	3.9	100
1970	447.8	312.8	572.5	58.3	1391.4	32.2	22.5	41.1	4.2	100
1975	586.1	418.1	661.6	67.2	1733.0	33.8	24.1	38.2	3.9	100
1980	734.4	524.1	793.8	73.7	2126.1	34.5	24.7	37.3	3.5	100
1982	729.2	514.1	770.7	79.6	2093.6	34.8	24.6	36.8	3.8	100
1985F	812.4	577.3	855.4	84.1	2329.2	34.9	24.8	36.7	3.6	100
1990F	972.8	717.7	958.6	101.5	2750.6	35.4	26.1	34.8	3.7	100
1995F	1109.6	843.4	1078.9	117.9	3149.7	35.2	26.8	34.3	3.7	100
2000F	1228.4	953.8	1206.5	133.3	3522.0	34.9	27.1	34.2	3.8	100

F = Forecast
Source: **Edison Electric Institute, Chemical Bank Forecasts.**

TABLE 2

AVERAGE ANNUAL ELECTRICITY DEMAND GROWTH BY END-USERS OVER THE PERIOD 1961-2000

(Percent)

	Residential	Commercial	Industrial	Other	Total
1961-65	7.42	12.04	4.70	6.40	6.90
1966-70	9.78	9.13	5.74	9.60	7.86
1971-75	5.57	6.04	3.03	4.54	5.63
1976-80	4.62	4.64	3.79	1.90	4.19
1981-85F	2.07	1.99	1.58	2.80	1.88
1986-90F	3.67	4.45	2.30	3.80	3.38
1991-95F	2.67	3.28	2.37	3.00	2.74
1996-00F	2.06	2.49	2.29	2.50	2.27
1961-70	8.60	10.59	5.22	8.00	7.38
1971-80	5.10	5.34	3.41	2.40	4.36
1981-90F	2.87	3.22	1.94	3.30	2.63
1991-00F	2.36	2.89	2.34	2.80	2.51
1961-73	8.32	10.06	5.47	7.00	7.29
1974-82	3.13	2.96	1.39	2.40	2.35
1983-90F	3.67	4.26	2.77	3.10	3.47

Source: **Edison Electric Institute, Chemical Bank Forecasts.**

COMMERCIAL SECTOR DEMAND

As the U.S. economy has become ever more service intensive, the commercial sector has increased in relative importance. Employment in the commercial sector relative to all nonagricultural employment climbed from 55 percent in 1960 to 66 percent in 1980. This expansion stimulated the sector's demand for energy, which increased at an annual rate of 3.5 percent—substantially faster than the 2.2 percent rate for both the residential and industrial sectors. Electricity sales to this sector grew at a rapid rate in the 1960s, averaging 12 percent a year in 1961-65 and 9.1 percent in 1966-70 (Table 2). Growth rates slowed in the 1970s to 6 percent in the first half of the decade and to 4.6 percent in the second half.

The sector's pattern of energy consumption by end use displays some distinct differences from residential energy demand. In particular, the dominant space heating fuels in 1975 were oil and gas, while only 6.5 percent of electricity went for heating commercial floor space in the same year, far less than the 20 percent use of electricity for space heating in homes.

In 1975, more than 75 percent of power consumption was for lighting and air conditioning—41.4 percent for lighting and 36.2 percent for air conditioning. Such uses as refrigerators, freezers and elevators accounted for another 15 percent. Lower temperature settings mandated by the government in 1979 after the second oil shock have already affected the level of electricity consumption in this sector. We estimate the reduction to be 15 to 20 billion kWh, roughly 3 to 4 percent of 1981 sales.

New structures are now built to be more energy efficient, thus lowering usage of energy in all forms. Lighting fixtures are placed to provide illumination where most needed. Moreover, lights are no longer centrally controlled as in many older structures; switches are put in each office area or room. Such adjustments, however, take a long time to work their way through the stock of commercial building space. Thus, their impact means a gradual diminution in energy requirements, lowering the rate of growth in electricity sales.

Although commercial markets for air conditioning in most parts of the country are nearing saturation, the Sun Belt alone offers potential for considerable expansion. Contributing to electricity demand growth is the trend toward a service-oriented economy, which will result in increases in the number of commercial customers and in commercial floor space. Adding to increased utilization of electric power is the expected growth of white-collar workers, who occupy more electric intensive space than other workers. Limited substitutability of electricity for oil and gas will bring only small gains for electricity in heating, mainly in areas where mild winters are typical.

We forecast that commercial demand for electricity will increase in the second half of this decade by 4.4 percent per year, somewhat lower than the 4.6 percent yearly growth in the 1976-80 period but considerably higher than the 2.0 percent rate in 1981-85 which was affected by the recession during 1980-82. For this decade the average annual rate of increase will be 3.2 percent, down from 5.3 percent in the 1970s. In the 1990s the average rate of growth will drop to 2.9 percent, the result of smaller population gains and, therefore, lower growth in the labor force and the demand for services.

INDUSTRIAL SECTOR DEMAND

The industrial sector has always been the largest consumer of electricity. In 1960 half of total power sales went to industrial customers. Its relative importance shrank steadily in the 1960s, however, primarily because of stepped up sales to residential and commercial users. Thus, the industrial share dropped from 50.5 percent in 1960 to 41.1 percent in 1970 (Table 1). The share continued to head down in the 1970s, although at a noticeably less rapid rate. It had declined to 36.8 percent in 1982. Despite losses in share, sales in absolute terms rose from 345 billion kWh in 1960 to 573 billion in 1970 and to 794 billion in 1980. More than 70 percent of electricity sold to industry is used by materials producers; chemicals and primary metals alone account for 44 percent. Since production of materials is highly sensitive to the business cycle, sales of electricity to this sector move sympathetically with recessions, though changes are not proportional since lighting and air conditioning requirements are not directly linked to production activity.

The outlook for industrial demand for electricity depends on the level of U.S. economic activity, the mix of industrial output, and trends in technology. The availability of low cost and abundant supplies of electric power has made possible the development of technologies—computers being a prime example—that have helped raise the nation's productivity. Conversely, such new technologies as robotics, microwave and induction heating, and electro-mechanical devices are creating new markets for electricity. On the other hand, the same applications could curtail power consumption by eliminating or reducing the need for processes that consume electricity; for example, in replacing people robots may reduce the need for air conditioning.

Some industry developments may hurt demand for electricity. U.S. companies can build new plants elsewhere in the world to take advantage of much lower energy and feedstock costs. Aluminum, steel and chemicals are mentioned as candidates. Further, newer plants are more energy efficient. For example, vintage aluminum plants required nearly 8 kWh to produce one pound of the metal, whereas less than 6 kWh will do in a modern facility. Other developments suggest the potential for higher consumption. The paper industry can switch to electric-motor driven machinery from gas-fired steam drive. While steel production in the U.S. has declined sharply due to depressed markets and stiff competition from imports, the share of domestic output from electric arc furnaces has risen from 11.8 percent in 1967 to 28.3 percent in 1981. This trend will continue and thus the steel industry will consume more electricity.

We estimate that demand for electricity in the industrial sector will show an annual average rate of growth of 1.6 percent for the 1981-85 period, far less than the 3.8 percent rate experienced in 1976-80. For the balance of this decade the average growth rate is estimated at 2.3 percent (Table 2). Annual increases will be 2.4 percent in the first half of the 1990s and 2.3 percent in the second half. These estimates imply that electric use in the industrial sector will grow more slowly than usage in the residential sector. By around 1989, residential demand will match industrial demand and will exceed it for the first time in 1990.

OTHER SECTOR DEMAND

Sales of electricity to public authorities, street and highway lighting, railroads and railways, and inter-departmental account for the rest of total demand. In the 1961-1973 period these sales accounted for 4.1 percent of the grand total and thereafter have averaged 3.7 percent. We expect these sales through the end of this century to generally track combined overall sales to the residential, commercial and industrial sectors; consequently, we forecast that the share will remain around 3.7 percent.

SUPPLY

In the 1960s, healthy and steady growth in electricity demand was almost universally accepted to be the rule. This assumption was evidenced in plans for large additions to capacity. After the oil embargo in 1973, however, the strong growth anticipated in the 1960s never materialized. As a result, the reserve margin—the ratio of excess capability to peak load demand—jumped from a nearly optimal level of 20.8 percent to more than 30 percent after 1974. The ratio reached 39.3 percent in 1982. Many projects are expected to come into operation between now and 1992, despite intervening delays and cancellations and the financial difficulties afflicting many utility companies. Through 1986, capacity will arrive at the rate of 15 million kW and will start declining thereafter; by 1992 those projects currently under construction and intended to go forward will be completed.

From an estimated peak of 41.2 percent in 1983, the reserve margin will gradually decline to 25.2 percent in 1990 and 20.0 percent in 1992. Improvements in the control of the nationwide power grid, higher utilization of oil- and gas-fired plants, and enhanced capability achieved through a greater emphasis on plant maintenance could provide reliable supply through 1993. Thereafter, new plants must come on line in order to avoid blackouts, brownouts and excessive reliance on expensive and uncertain supplies of oil and gas for baseload generation.

Given the long lead times for construction, work on new orders should theoretically start around 1987. In certain regions, however, power shortages are likely to develop earlier, so these utilities will have to begin work on new capacity before 1987. Thus, new orders will commence around 1986 at the rate of 12 million kW, gradually rising to 19 million kW (nameplate) by the end of the decade. Orders in the first half of the 1990s will run around 21 million kW a year. They will then climb to 27 million kW by the year 2000, reflecting the need to replace about 44 million kW in the second half of the 1990s. We estimate that total net additions in the 1990s will amount to 149.3 million kW, compared with 135.5 million in the 1980s, 272.6 million in the 1970s and 173.1 million in the 1960s. The amounts of installed capacity by input energy, capability at peak load, peak load demand and reserve margins are shown in Table 3.

Only coal and nuclear fueled plants are feasible choices for significant new power supplies for the long run. Large hydroelectric sites have already been exploited. We expect that by the end of the century about 8 million kW of new hydro capacity will come from small, low-head projects. Oil-based generating costs are very high and, more importantly, such capacity depends on unreliable supplies of imported oil. Limited reserves of natural gas and the prospect of price decontrol mean that much new gas-based capacity is unlikely; such nonconventional sources as solar, wind, biomass and geothermal offer minor potential for generation, not to exceed a total of 12 million kW by the end of the century. Imports of electricity from Canada will continue to be a minor alternative source of supply for the U.S. in the longer term.

The technical results and economics of 14 demonstration plants that were built in the 1950s and began operating in the early 1960s became the subject of intense interest to both utility companies and manufacturers of nuclear reactors. From 1966 to 1974, utilities placed large orders for central station nuclear plants, totaling 218 units with 224 million kW of capacity. The relatively short period of commercial-scale experience, coupled with the acceleration of reactor orders and the upscaling of unit sizes, produced some unpleasant surprises.

TABLE 3

U.S. ELECTRIC POWER SUPPLY: 1965-2000
(Million Kw)

	1965	1970	1975	1980	1985F	1990F	1995F	2000F
Installed Capacity	236.1	341.1	508.4	613.7	697.2	749.2	806.3	898.5
Hydro	43.8	55.1	65.9	76.4	79.5	83.3	84.8	86.3
Nuclear	0.9	6.5	39.8	56.5	85.3	102.4	99.9	92.3
Steam	188.1	275.2	397.6	475.3	525.3	554.3	609.9	705.9
Other	3.4	4.4	5.1	5.6	7.0	9.2	11.7	14.0
Capability, Peak Load	228.9	326.9	479.3	558.5	637.9	683.5	748.8	840.6
Peak Load Demand	186.3	274.6	356.8	427.1	461.7	546.2	625.2	701.6
Reserve Margin %	22.9	19.0	34.3	30.8	38.2	25.2	19.8	19.8

F = Forecast

Note: Other includes nonconventional sources and internal combustion.

Source: **Edison Electric Institute, Chemical Bank Forecasts.**

The capabilities of manufacturers and vendors were severely strained to meet large and ever more complicated obligations. Perhaps more importantly, concerns for public health and safety led to the imposition of regulations and standards unforeseen by nuclear planners. As a result, the process of licensing and construction steadily lengthened, adding to costs. By the mid-1970s, project costs appeared to be out of control. In addition to regulation, labor productivity deteriorated, problems with the production of materials and equipment mounted, and labor strife caused further delays in general construction. Still stricter standards imposed after 1970 required significant increases in material and labor inputs. For example, stringent seismic designs and higher pipe support capability were mandated, boosting structural steel content twofold. Similarly, higher standards for radiation shielding doubled the concrete input. The degree of design complexity, quality assurance and specialized construction techniques all increased, causing worker-hours for design and construction to swell even faster.

By 1981 utilities—facing slower demand growth, large construction programs with runaway costs, and the need to raise significant amounts of external funds—canceled 84 units and delayed completion of many others. Moreover, the Three Mile Island incident in 1979 was a grievous blow to the future of nuclear power. In the aftermath of the accident, new regulations mandated equipment retrofits and additions, to be incorporated not only in new power plants but also in existing ones. The most important repercussion, however, has been the tough stance taken by the Nuclear Regulatory Commission in holding up the licensing of units that contain construction flaws. The interest charges accumulated while the plant is delayed typically run at several hundred million dollars per year in addition to the cost of the repairs. This has led to considerably higher costs of completion, which will exceed $2.5 billion for many units.

The operating performance of nuclear plants varies by unit size. In particular, the unit forced outage rate (FOR) for plants larger than 800 MW is 18.3 percent, considerably greater than the 6.7 percent for smaller reactors in the 400 and 799 MW range. Various studies have analyzed the relationship between age of plants and capacity. These studies indicate that small gains in capacity are achieved as units mature:

- Small plants (400-599 MW) mature in about 4 years, from an average initial capacity factor of 57 percent to 75 percent.
- Intermediate-sized plants (600-799 MW) mature after 7 years, from an initial capacity factor of 55 percent to 67 percent.
- Large plants (800 MW and up) go from 55 percent to 61 percent after 3 years.

Experience thus far shows that initial expectations that reactors entering service in the period 1981-2000 would achieve an average lifetime capacity factor of 80 percent after two years of commercial operation will not be realized. Recent studies indicate that the outcome will be in the 50-65 percent range. Our estimates suggest that the utilization factor—defined as the percent of actual generation to the product of design capacity and hours in a year—will gradually move up from an average of 51 percent in 1980-82 to 56 percent by 1990 and remain at that level to the end of the century.

Capital fixed charges are an important component of the total cost of generation. These charges—together with operation, maintenance and fuel costs—determine the mix and viability of generating technologies. Based on generating cost data for the 1976-80 period for a comparable sample of nuclear and coal-fired plants, nuclear plants had on average a 10 to 20 percent advantage over coal plants prior to 1979/1980. The same sample of plants in 1982 revealed that coal had gained a 25 percent edge over nuclear plants in the South and held a commanding cost advantage of around 50 percent in the Middle Atlantic and Far West regions. Capital fixed charges accounted for 62.4 percent of total costs for nuclear plants and 35.7 percent for coal plants; operation and maintenance costs contributed 18.5 and 10.4 percent, respectively; finally, fuel costs were 19.1 and 53.9 percent, respectively. Given this distribution of generation costs, utilities will first of all operate nuclear plants, since their marginal costs are significantly lower. Nonetheless, historical costs do not consider the future expense of waste fuel management for nuclear plants. Likewise, future costs arising from the Clean Air Act Amendments of 1977 and New Source Performance Standards for sulfur dioxide and particulates are not taken into account—all new coal-fired plants must have scrubbers and precipitators and many old plants must be retrofitted. Operation and maintenance costs for plants with scrubbers have run about 2 to 4 mills per kWh higher relative to plants without scrubbers, depending on the quality of coal burned.

Jeopardizing the future of nuclear power are adverse financial conditions, lack of public policies for effective waste management, lower than expected operating performance, a poor public image on health and safety, and huge construction costs for many nuclear projects. These difficulties militate against the placing of more new orders that would have any bearing on nuclear capacity and generation during the forecast horizon. In fact, the problems of nuclear power—especially in the present context of large reserve margins—have prompted utility companies to cancel scheduled projects, including some not far from completion. Five nuclear installations came on line last year and seven more have been granted licenses to operate this year. At issue are 41 projects scheduled to come into operation by 1990.

We expect 36 nuclear plants to come into operation in the 1983-90 period, 24 more besides the 12 already in hand. The 36 will have a combined capacity of 38 million kW, bringing nuclear's total to around 102.4 million kW. This estimate is already down 31 million kW from what was scheduled a year ago, meaning that 155 billion kWh of lost generation must be made up from other sources. Some observers—including analysts from the financial community—are more pessimistic, predicting 24 units at most for 1983-90.

The low estimates seem to concentrate on short term problems of financing and licensing. Excessive cancellations or delays of nuclear projects could well lead to capacity adequacy problems by around 1991—or even as early as 1989 in the event of extreme weather. This short lead time provides no leeway to build efficient capacity. To bridge the gap, utilities will have to resort to high-cost oil and gas generation. Such measures as rationing and forced conservation—albeit undesirable—may also be invoked. Since an expanding economy will already be lifting the demand for fuels, this additional pressure on oil markets will raise prices as supplies tighten and more must be imported. Besides personal comfort and life style, at stake would be economic growth, productivity, inflation, America's competitive position in world markets, and its vulnerability to foreign supplies of oil.

In view of these considerations and the fact that coal is a secure source of energy, mined at home and in plentiful supply, we expect almost all of the new capacity additions after 1989 to be coal-fired. Coal-fired capacity in 1985 will be 47.4 million kW more than in 1980, while another 33 million kW will be available for operation by 1990 as most projects under construction or now in the planning stage are completed. Beyond present schedules, incremental coal-fired capacity will be an estimated 55 million kW by 1995 and another 96 million by the year 2000, in order to ensure reliable service.

Coal-based generation thus will rise from 50.8 percent of total power output in 1980 to 53.5 percent in 1985 and to 55.3 percent in 1990. In the 1990s, as most of the new capacity is coal based, coal's share will reach 58.3 percent in 1995 and 64.3 percent by 2000 (Table 4).

By the end of 1986 more than 35 percent of the total capacity additions will be nuclear; this development explains the sharp gains projected for nuclear-based generation, from 11.0 percent in 1980 to 16.0 percent in 1985. After 1986 capacity additions will be sharply smaller and the period around 1989 will mark the end of the era of growing nuclear capacity; likewise, nuclear-based output will constantly decline after 1990. Naturally, nuclear's share of total generation will slip, from 16.6 percent in 1990 (it actually peaks in 1988) to 14.1 percent in 1995 and to 11.6 percent by the year 2000. Nuclear technology, however, has reduced the country's dependence on insecure supplies of oil. Other things being equal, without nuclear generation the equivalent of an additional 2.29 million barrels of oil per day would be required in 1990 to meet demand.

Oil- and gas-based generation will be declining in absolute terms until 1985, when their combined generation falls to 429 billion kWh. Thereafter, as the reserve margin narrows and as utilities pursue capital conservation policies, these types of generation will rebound, reaching 474 billion kWh in 1990 and 565 billion in 1995. Since construction picks up strongly in the 1990s, the new coal-fired plants will supplant oil and gas generation, which then drops to around 515 billion kWh in the year 2000 (Table 5).

TABLE 4

ELECTRIC UTILITY POWER GENERATION BY ENERGY SOURCE
(Percent)

Energy Source	1960	1965	1970	1975	1980	1985F	1990F	1995F	2000F
Hydro	19.3	18.4	16.2	15.6	12.1	12.7	11.2	9.9	9.0
Nuclear	0.1	0.3	1.4	9.0	11.0	16.0	16.6	14.1	11.6
Coal	53.5	54.1	46.1	44.5	50.8	53.5	55.3	58.3	64.3
Oil	6.1	6.1	14.9	15.1	10.7	5.5	5.9	7.1	5.7
Natural Gas	21.0	21.0	24.3	15.6	15.1	11.5	10.1	9.6	7.9
Other	0.0	0.0	0.1	0.1	0.2	0.6	0.9	1.0	1.5

Note: Other includes geothermal, wood and waste.

F = Forecast

Source: **Edison Electric Institute, Chemical Bank Forecasts.**

TABLE 5

ELECTRIC UTILITY POWER GENERATION BY ENERGY SOURCE: 1960-2000
(Billion kWh)

	Hydro	Nuclear	Coal	Oil	Gas	Other	Total
1960	145.5	0.5	403.1	46.1	158.0	0.1	753.3
1965	193.9	3.7	570.9	64.8	221.6	0.4	1055.3
1970	247.5	21.8	706.1	182.5	372.9	0.8	1531.6
1975	300.1	172.5	853.0	288.9	299.8	3.4	1917.6
1980	276.0	251.1	1162.0	245.5	346.2	5.6	2286.4
1985F	318.9	401.4	1339.2	139.0	290.3	16.2	2505.0
1990F	330.5	489.7	1634.2	175.4	299.0	27.5	2956.3
1995F	334.4	476.5	1973.7	241.0	324.0	34.0	3383.6
2000F	342.0	437.4	2434.7	217.0	298.1	57.2	3786.4

Source: **Edison Electric Institute, Chemical Bank Forecasts.**

FUEL CONSUMPTION

The U.S. is a major producer of coal. Most recent estimates put its coal reserve base at 473 billion tons, of which 246 billion tons can be recovered by conventional mining methods. This estimate represents about 25 percent of known recoverable world reserves and is sufficient to last for 340 years at current rates of production. Electric utilities are the most important end-users of coal; their consumption increased by 6.1 percent per year over the period 1961-70 from 176.6 million short tons in 1960 to 320.8 million in 1970. Utilities' consumption continued to grow at a high rate (5.9 percent per year) in the 1970s, despite the dramatic decline in the growth of electricity demand and, hence, generation. Thus in 1980, utilities burned 569.5 million short tons, which was 81 percent of total U.S. coal consumption. The trend favoring higher usage of coal for electricity generation will continue in the 1980s and 1990s. We expect coal consumption to reach 814 million tons in 1990 and 1232 million tons in 2000 (Table 6). This corresponds to annual growth rates of 3.6 percent and 4.2 percent for the 1981-90 and 1991-2000 periods, respectively. The slowdown in the growth of coal consumption in the 1980s is the result of smaller increases in demand for electricity and the increase of nuclear generating capacity. The increase in coal usage in the 1990s is the outcome of the shift in generating capacity in favor of coal.

Natural gas is used to produce electric energy mainly in the ERCOT (Texas) and SPP (Southwest) regions. In 1982 about 60.4 percent of the electric energy produced in ERCOT was from gas, down from 67.5 in 1980; in SPP gas accounted for 48.4 percent of the total electric supply, down from 59.4 in 1980. In the 1980s scheduled additions of nuclear and coal-fired

TABLE 6

FOSSIL FUEL CONSUMPTION BY ELECTRIC UTILITIES: 1960-2000

	Coal (Million short tons)	**Oil** (Million barrels)	**Gas** (Trillion cubic feet)
1960	176.6	85.3	1.725
1965	244.8	115.2	2.321
1970	320.8	335.5	3.932
1975	406.0	506.1	3.158
1980	569.5	420.2	3.682
1985F	660.3	237.1	3.068
1990F	813.9	299.2	3.160
1995F	991.6	411.2	3.425
2000F	1232.4	370.2	3.150

F = Forecast

Source: **Edison Electric Institute, Chemical Bank Forecasts.**

capacity in ERCOT and SPP—amounting to 34 million kW-will reduce the use of gas. Thus, gas-fired generation will decline somewhat through 1985 to 290 billion kWh and then start to come back as demand increases. We estimate the total at 299 billion kWh in 1990, rising to a peak at 324 billion in 1995 and then dropping to 298 billion kWh in 2000. The reason for the upturn is that demand growth is expected to exceed the national average in these two regions, surplus electricity in other U.S. regions will be declining as the national reserve margin falls, and planned coal-fired capacity will not be enough to meet all the needs. The Fuel Use Act has been modified to allow the continuation of gas usage in generation. Without this modification use of natural gas would have been prohibited after 1989.

These trends will cause gas usage to produce electricity to drop from 3.226 trillion cubic feet (tcf) in 1982 to 3.068 tcf in 1985; it will then start rising, reaching 3.160 tcf in 1990, 3.425 tcf in 1995, and then fall to 3.150 tcf in 2000 (Tble 6). Gas generation at current levels of capacity cannot exceed the historical high of 376 billion kWh achieved in 1972. There are two reasons why: first, the cost of gas generation is higher relative to coal and nuclear power and it will continue to move up significantly as gas is decontrolled in 1985. Secondly, domestic proved reserves of natural gas as of the end of 1981 were 202 tcf, or about 11 years of supply at current levels of production (17.8 tcf). Net imports, which now provide about 0.9 tcf (mainly from Canada and Mexico via pipeline), do not offer a viable alternative for generation expansion.

Oil is used by the electric utilities as an input fuel most in the NPCC (Northeast) and MAAC (Mid-Atlantic) regions, in Florida, a subregion of SERC (Southeast), and in California, which is part of the WSCC (West) region. Based on 1982 NERC statistics, their combined oil-based generation amounted to 124.5 billion kWh or 85 percent of the national level of 146.4 billion kWh. Oil-based generation in 1982 was 40.4 percent less than in 1980 (245.5 billion kWh) and was 59.5 percent lower than the all time high of 364.2 billion kWh in 1978. This dramatic decline reflects the efforts of utilities in these areas to minimize reliance on imported oil through the installation of new nuclear and coal-fired capacity, conversion of existing oil-fired capacity to coal, conservation and load management programs, and imports of electricity from Canada or other U.S. regions with surplus electric power. We expect oil-based generation to fall to around 136 billion kWh this year and next. It should then start rising somewhat as the national reserve margin slips below 35 percent. We predict that oil-based generation will increase to around 175 billion kWh in 1990; it will peak in 1995 at 241 billion and then fall to 217 billion kWh in 2000 (Table 5). As a result, oil usage for electric power generation will fall to around 237 million barrels through 1985, from 420.2 million in 1980, before gradually increasing to 299 million barrels in 1990 and 411 million in 1995; thereafter it will begin to decline to 370 million barrels in 2000 (Table 6). The level achieved in 1995 will still be less than two thirds of the 636 million barrels used in 1978.

IMPORTS OF ELECTRICITY

Imports of electricity from Canada and Mexico have been a small but growing component of the total U.S. electric supply. In 1970 net imports were only 2 billion kWh, or 0.1 percent of total electric utility generation. By 1980 net imports reached 27.2 billion kWh, or 1.2 percent of electric utility supply. Canada is the most important net supplier of electricity to the U.S.; net imports of electricity increased from 9.2 billion kWh in 1976 to 33.9 billion kWh in 1981.

Electricity from Canada largely comes from hydroelectric installations, which enjoy operating cost advantages relative to other fuels. In recent years Canada has had excess capacity, due to large increases in hydroelectric generating capacity and slower than anticipated growth in demand. This surplus created opportunities for increased sales to U.S. utilities, particularly those eager to avoid operating their own costly oil-fired units and even the need to add capital-consuming capacity.

While only a small fraction of total U.S. electric generation, Canadian power is a significant contributor to supplies in some parts of the U.S. In 1981, it accounted for 11.3 percent of the electricity generated in New York, 4.4 percent in New England and 3.6 percent in the MAPP (Mid-Continent) area.

The outlook for imports depends on excess capacity, transmission capabilities, world oil prices, pricing methods, and Canadian energy policy. At present, Canadian electricity is usually priced at a percent of the avoided cost of oil-generated electricity.

Two new transmission lines with 2.45 million kW of capacity to New York are expected to be in operation by 1984. These lines will increase New York's potential imports by 78 percent. New England plans to build one line with ultimate capacity of two million kW by 1990. This line would triple the area's import potential. By 1986, MAPP's import potential will increase by 64 to 96 percent with the building of a new transmission line with capacity of either 1.0 or 1.5 million kW. Utilities in California and the Northwest import from British Columbia, almost exclusively hydroelectric power. Although the level of imports is substantial, it constitutes only a small fraction of the total electricity consumed in these regions. Any substantial trade expansion will necessitate new transmission lines between the Northwest and California, for which there are no plans.

Current Canadian national policy requires that utilities build generating capacity to meet only Canadian electricity demand. Installed capacity in 1980 for Canadian border provinces amounted to 72 million kW—88 percent of the nation's capacity—and was 57 percent hydro-based. Total capacity is projected to grow by 3.9 percent per year to 145.3 million kW in 1995. Hydroelectric capacity will continue to be the dominant source, projected to make up 53 percent of the new added capacity. Growth in Canada's demand over the same period is estimated at 4.5 percent, which implies that a narrowing internal excess will curtail some of the potential for sales to the U.S.

We conclude that the interconnections between U.S. and Canadian utilities provide greater stability and reliability for the electric power systems of both countries. They permit large short-term transactions which raise operating rates and, hence, profitability. In the short-term U.S. utilities can reduce their dependence on oil-fired generation through imports. Nevertheless, U.S. purchasers do not receive much of a windfall. The current pricing formula sets the import price at around 80 percent of the avoided cost of U.S. oil-generated electricity, rather than at the much lower cost for hydropower. In the long-run, imports from Canada will be attractive as long as pricing is competitive with the domestic cost of generation and domestic backup is available. Given capacity limits and Canadian policies, imports will represent a limited source of long-term supply for the U.S.

CAPITAL SPENDING REQUIREMENTS

Expenditures by investor-owned electric utilities for new plant and equipment are expected to decline gradually in real terms and to be flat-to-down in nominal terms from 1983 to 1986. Of the projects currently being constructed 55 percent are due to be finished and come into service by the end of 1986. For the 1983-86 period capital outlays are projected to total $127.7 billion (current prices). As new orders reappear, around 1986, the decline in capital spending will slowly end by 1988 and spending will edge higher over the rest of the decade and then proceed on a strong uptrend in the 1990s.

Total capital spending for generation, transmission and distribution from 1981 to 1990 will amount to $311.3 billion current dollars, of which $61.9 billion has already been spent in 1981-82. This will bring 113 million kW of new capacity at a cost averaging $2754 per kW. The average cost per kW has thus soared 205.3 percent from $902 in 1971-80. In 1980 dollars, the average unit cost of net new capacity over the 1981-90 period will be 48.6 percent greater than the 1971-80 average ($2009/kW vs $1352/kW). The main causes for these record increases in unit investment outlays are higher financing costs, inflation in construction, delays in licensing, and regulatory requirements.

In the 1990s, assuming a 7 percent inflation rate for construction, average capital expenditures per unit of net new capacity additions will be $4900 per kW or 80.5 percent higher than the 1981-90 average, a far more modest rise than that in the preceding decade. The basic reason for expecting smaller cost increases is that almost all of the new capacity will be coal-fired, costing less than nuclear plants even after allowance for scrubbers and precipitators. On average, pollution control facilities raise capital outlays per plant by 20 to 30 percent; therefore, in 1980 dollars the average spending per kW will be in the range of $1064 to $1160 in the 1990s, compared to an average of $967 in 1980. As a result, we estimate total new capital spending requirements in the 1990s to amount to $613.3 billion for capacity additions of 123.4 million kW and capacity replacement of about 34 million kW anticipated to be retired in the second half of the 1990s (Table 7).

TABLE 7

CAPITAL EXPENDITURES FOR NEW CONSTRUCTION OF ELECTRIC POWER[1] SYSTEMS BY INVESTOR-OWNED UTILITIES: 1960-2000

	Total Capital Expenditures	**Net Capacity Addition**	**Cost per Unit of New Capacity**	**Cost per Unit of New Capacity**
	(Billion Dollars)	**(Million kW)**	**(Dollars/kW)**	**(1980 Dollars/kW)**
1961-1970	53.9	134.2	402	967
1971-1980	193.2	214.4	902	1,352
1981-1990F	311.2	113.0	2,754	2,009
1991-2000F	613.3[2]	123.4	4,900	2,174

F = Forecast

[1] Includes spending for generation, transmission, distribution and other.

[2] Includes spending for replacement of 34 million kW expected to be retired.

Source: **Edison Electric Institute, Chemical Bank Forecasts.**

By region, capital outlays over the 1981-2000 period will be greatest in the SERC area, amounting to $243 billion for 26 percent of total U.S. capacity additions. WSCC will follow with $190 billion for about 21 percent of national capacity additions. Capital spending in ECAR (East Central) will be about $157 billion for 17 percent of new U.S. capacity. The ERCOT and SPP regions will absorb around $111 and $95 billion, respectively, for 22 percent of the industry-wide total. Finally, the remaining capacity additions of around 15 percent will take place in the other four regions—MAAC, MAIN, MAPP and NPCC—each of which will require around $33 billion.

FINANCING NEEDS AND DEVELOPMENTS

Electric utilities always have relied heavily on external financing for the construction programs needed to meet future energy demand. During the 1960s the industry enjoyed stable fuel prices, declining costs of generation from technical advances and economies of scale, minimal environmental constraints, short construction lead times, and steady growth in electricity demand (at about 7 percent annually). These factors combined to drive down electric rates paid by consumers (Table 8). At the same time, investor confidence ran high as the rate of return on equity usually exceeded what public utility commissions (PUCs) allowed. The realized rate of return was higher because state PUCs set rates on the basis of historical costs, while in fact current costs were declining; PUCs let utilities retain excess profits as capacity expanded and electricity prices fell. In the 1961-68 period, rate-of-return reviews by state PUCs averaged only five per year, confirming that both consumers and producers were satisfied.

TABLE 8

FINANCIAL STATISTICS OF ELECTRIC UTILITIES, 1960-2000

	1960	1965	1970	1975	1980
Utility Earned Rate of Return on Equity (percent)	11.5	12.9	12.2	11.5	12.0
Allowed Return on Equity (percent)	—	—	—	12.9	14.1
Earned Rate, excluding AFUDC (percent)	10.8	12.4	10.0	8.3	6.4
Earned Rate of Return, All Mfg. (percent)	10.6	13.9	10.1	12.6	16.4
Bond Yields (percent)	4.8	4.7	8.8	9.8	13.0
AFUDC as a Percent of Net Income	5.7	3.7	17.8	28.2	46.3
Real Average Revenue per kWh Sold (1980 Cents)	4.70	4.05	3.26	4.15	4.70
Real Cost (1980 Cents)	3.95	3.36	2.74	3.77	4.53

Source: **Promoting Efficiency in the Electric Utility Sector. Congressional Budget Office, Nov. 1982.**

In the late 1960s, once economies of scale were essentially exhausted and further cost cutting proved much more difficult, the rate of return earned by utilities started to head down. The squeeze on electric utility profits intensified in the 1970s as the general inflation worsened, fuel costs and the cost of financing surged, construction lead times lengthened, and the growth of demand for electricity fell by half. The Clean Air Act (1970) and its amendments (1977) imposed strict controls on solid waste and emissions of sulfur dioxide and particulates. This brought more pressure on generating costs, which rose from about 2.8 cents (1980 dollars) in the late 1960s and early 1970s to 3.8 to 4.1 cents in the second half of the 1970s and to 4.5 cents in 1980.

These developments forced down the earned rate of return on equity, which after 1975 fell short of utilities' allowed rates of return on common equity. By 1980, the differential was two percentage points—12.0 percent actual vs. 14.1 percent allowed. When AFUDC accounts are excluded from earnings—AFUDC is a non-cash income item representing the carrying cost of capital spent for construction work in progress (CWIP)—utilities' earned rate of return fell even more dramatically, from 9.1 percent in 1972 to 6.4 percent in 1980. By comparison, the rate of return for all manufacturing rose from 12.1 percent to 16.1 percent over the same span. The decline in the rate of return on capital, the adverse cost trends and the general reluctance of PUCs to grant timely and sufficient rate relief combined to undermine the credit ratings of many companies. This downgrading naturally added to the already high cost of long-term finance.

To lighten excessive fixed charges, utility companies have worked down their long-term debt ratios to about 50 percent from 52.7 percent in 1975 (Table 9), raising the capitalization ratio for common stock to 26.8 percent from 22.5 percent in 1975. Retained-earnings-to-capital has inched up as well, to 12.3 percent from 12.1 percent in 1975. Regulatory authorities have recently responded to the industry's distress by providing much needed financial relief in the form of larger rate increases and a greater allowed rate of return on equity (15.9 percent in 1982, up from 15.2 percent in 1981).

With long-term interest rates now below their earlier highs and with a slower uptrend in fuel costs, pressures on consumer electric rates should ease. The price of oil fell from $33.10 per barrel in 1981 to $29.80 in 1982 and was down to $29.30 in the third quarter of 1983. Cost moderation affords PUCs breathing room for more rate relief because the public will find smaller price increases more palatable. As the reserve margin begins to improve after 1983, capital fixed charges per unit of generated output will come down, resulting in improvements in the realized rate of return on equity.

The Economic Recovery Tax Act of 1981 (ERTA) provided business with accelerated depreciation. For utilities, asset lives for tax purposes were trimmed from 28 years to 15 years for fossil fuel plants and to 10 years for nuclear plants. Transmission and distribution equipment can be written off in 15 years instead of 30 years. ERTA also expanded investment tax credits (ITC) on plant and equipment, allowed tax deferrals for individuals reinvesting stock dividends in qualified utility stocks, and allowed the sale of depreciation and ITC tax benefits. The Tax and Fiscal Responsibility Act of 1982 (TEFRA) reduced the benefits for capital investment somewhat. It reduced future accelerated depreciation, restricted the sale of tax benefits, and required interest and tax payments on real property incurred during the construction period to be capitalized rather than be expensed. Nonetheless, the net effects will benefit the utility industry by enhancing funds from internal sources.

TABLE 9

EXTERNAL FINANCING OF INVESTOR OWNED ELECTRIC UTILITIES
(Billion Dollars)

Period	Total	Long-Term	Pref. Stock	Common Stock
1971-80	113.3	64.2	16.5	30.5
1981-90F	97.1	56.0	14.5	26.7
1991-00F	230.5	132.7	33.8	64.0

	Capitalization (Billion Dollars)			Capitalization Ratios (Percent)		
	1975	1981	1982	1975	1981	1982
Common Stock	29.2	59.2	67.6	22.5	26.0	26.8
Retained Earnings	16.0	27.5	31.1	12.1	12.1	12.3
Preferred Stock	16.9	26.8	29.0	12.7	11.7	11.5
Long-Term Debt	69.9	114.6	124.8	52.7	52.7	49.4
Total	123.6	228.1	252.5	100.0	100.0	100.0

Source: **Edison Electric Institute, Chemical Bank Forecasts.**

The financial position of electric utilities should improve steadily in this decade. The proportion of investment financed externally will drop from an estimated 43.5 percent in 1983 to as low as 15 percent in 1988. There are two primary contributing factors. First, current-dollar investment will run around $33 billion per year through 1986; investment will then edge down as 55 percent of projects under construction reach completion. Second, these projects will enter the rate base and, therefore, boost cash flow markedly. Under the assumption that current regulatory conditions prevail, investor-owned utilities' needs for external financing are estimated at $97.1 billion for the 1981-90 period, or 30.3 percent of total investment including AFUDC. In 1981 and 1982 external funds amounted to $13.8 and $15.5 billion. For 1991-2000, funds from outside sources will total $230.5 billion or 37.6 percent of total investment (Table 9). By comparison, external needs in the 1971-80 period were $113.3 billion or 58.6 percent of the total.

Once it is clear that utilities are going to be financially strong again, regulators can be expected to act on the acid rain issue. Likewise, the influx of coal-fired capacity will engender demands for still tighter emission controls. Thus, once this year's elections are past—say by 1986—the movement to force still more pollution abatement outlays should gather momentum. At a minimum, the upshot will be an additional $20 billion to industry investment outlays over the rest of the 1980s, i.e., external needs would be $117 billion for the decade.

IF THE LIGHTS GO OUT? -- THE DAY AFTER

Eugene N. Oatman
Electric Power Research Institute
Palo Alto, California

Although the nation's electric utilities have sufficient generating capacity to serve the needs of today's customers, the prospects for increasing generating capacity to meet future requirements are far from certain. And although substantial progress has been made on national resolutions to reduce dependence on oil and gas, the price has been high and our lives and livelihoods have changed in ways that have darkened perceptions of the future. Because the consequences of failing are sufficiently severe and the lead time for responding sufficiently long, it is appropriate to consider the question, "If the lights go out?" before it becomes "When the lights go out".

Even under the most conservative assumptions, new capacity will be needed for economic growth and to replace aging plant. However, in today's business environment, there are strong disincentives against capital investments of any kind. Each year as more committed generation is cancelled and planned capacity postponed, the future electricity supply becomes less tangible, the capability of the industry to respond less certain, and the spectre of future shortages more ominous.

The ability to forestall an impending shortage depends upon the lead time and potential effectiveness of available options. The paper examines the initial loss of new baseload coal and nuclear capacity (with the commensurate loss of manufacturing capability, engineering skills and project management expertise).

Finally, the paper addresses the broad range of economic consequences of electricity shortages of varying durations on particular classes of customers. While these shortage costs represent many times the actual price of electricity, they fail to convey the political and economic turmoil likely to result from a widespread shortage of electricity. If experience is a guide, coping strategies are unlikely to be effective. Errors in energy planning are costly. Uncertainty increases the likelihood of error. It is important to discriminate between those errors that impose additional carrying charges in insurance and the potentially disastrous consequences of having too little capacity.

use of energy. Consumption per unit of GNP has declined by 20 percent over this decade. In 1981, the economy used about the same amount of total energy as it did in 1973, with a further decline of 5 percent in 1982 on the winds of a severe recession (1).

We haven't achieved all that we resolved, of course. Our goals for substantially replacing oil and gas have been thwarted, in part, by the concerns of the environmental effects of coal and uranium use. Moreover, the price has been high and there is evidence that we have not yet finished paying. Many of our economic and productive institutions are in a state of uncertainty and, in some instances, near chaos. In exchange for decreased vulnerability to oil disruptions we have increased our vulnerability in other areas, as sharply higher energy prices have driven the production of basic materials overseas.

In some fundamental respects, we are better off than we were in the halcyon days before our abrupt awakening to ever increasing vulnerability. But, in other respects, our lives and livelihoods have changed in ways that have darkened perceptions of the future. This change in attitude is reflected best by the fact that today's high school and college students don't expect to be better off than their parents were--a fundamental reversal of the American "right" of increasing expectations.

The challenge we face as a nation is to restore the right of increasing expectations to our children and to their children. The challenge the electric utility industry faces is to ensure that the resumption of economic growth in this country will not be constrained for want of a reliable supply of electricity. A corollary challenge is to exploit the productivity increasing value of electrification to improve the competitiveness of U.S. products in the world market. But despite the fact that there is an adequate supply of electricity for today's needs, the prospects for increasing generating capacity to meet future requirements are far from certain. The consequences of failing to meet those challenges are sufficiently severe, and the lead time for responding sufficiently long, that it is appropriate to consider the question, "If the lights go out?" before it becomes, "*When* the lights go out."

IF THE LIGHTS GO OUT?--TURNING THEM OFF

"Will the Last Person Leaving Seattle Please Turn Out the Lights"

This billboard from a few years back is a reminder that, in addition to a failure of the electricity production and delivery system, there is still another way for the lights to go out--they can be turned off when the plant is closed. In fact, much of the political and regulatory risk that makes it imprudent for utility decision makers to commit scarce capital resources for generating facilities that will be needed in the next decade arises from a widespread perception that additional supplies of electricity will not be needed because America, in essence, is going out of business.

A further concern with declining activity in utility contruction is the loss of manufacturing capability, engineering skills and project management expertise among suppliers, constructors and within utilities. Consequently, the response to a sudden realization of need for new capacity will be inefficient, requiring a long startup, with a commensurate loss of quality control and productivity. Moreover, following a prolonged period of inactivity, regulatory staffs will find it difficult to respond in a timely manner to utility requests for siting and licensing permits, possibly renewing the regulatory lag prevalent in the early 1970s.

The exchange of power among utilities has benefits both for the economic operation of the lowest cost plants and for protection against sudden outages. The effectiveness of this option, from a reliability standpoint, depends upon mutual strength of reserves and cannot be sustained if individual systems slip into a dependency relationship. Further, it is physically impractical for electricity demands in the Southwest to be permanently sustained by generating capacity that may be available in the Northeast.

Finally, the option with the shortest lead time is the elimination of marginal electricity consumption through conservation and demand management programs. Price increases of the last decade have resulted in substantial reductions in electricity usage and it is fair to say that the easy savings already have been achieved. In particular, the price of electricity to industrial consumers has risen at an average annual rate of 8.15 percent over the past decade compared with 3.68 percent and 4.25 percent for residential and commercial customers (3). These price increases have provided strong incentives for industrial customers to improve the efficiency of electricity usage, including commitment of capital in heat recovery systems, demand management devices, and process changes. Moreover, many of the opportunities for increasing the competitiveness of U.S. products through improvements in productivity involve increased use of electricity. Significant further reductions may come at the cost of a further decline in international competitiveness.

IF THE LIGHTS GO OUT?--EFFECTS AND CONSEQUENCES

Effects By Region

Because of regional differences in climate and economic growth, the incidence and impact of electricity shortages are unlikely to be uniform across the nation. For reliability purposes the country is divided into nine regional councils. Among these nine regions, Texas and the Southwest Power Pool (Oklahoma, Louisana, Arkansas, Kansas and part of Missouri) are projected to be first and second in the rate of peak demand growth over the coming decade (4.1, 3.1 percent). Appropriately, these regions also rank first (3.4%) and third (2.4%) in planned resources. However, by 1992, these regions have the smallest (17 percent) and third from smallest (20 percent) projected capacity margins among the nine regions (4).

If economic growth and electricity demand should rise more rapidly than anticipated, or if new generating capacity schedules electricity supply. Short run costs in the industrial sector result from idle labor and capital resources, losses of raw material and in-process production, equipment damage, shutdown and restart expenses and health and safety risks. Long-run costs stem from changed time-of-use patterns, larger inventories, standby generation, substitution of other fuels and readjustment of output patterns. Outage costs estimates for industrial customers range from (5¢-$1/kWh) for energy shortages to ($1-$7/kWh) for capacity shortages (7).

A number of specific studies of industrial outage costs have been conducted. Warren Devine (Oak Ridge Associated Universities) studied outage costs for six industrial plants in the TVA region and found miminum total annual costs averaging between $286 thousand for a one hour, once per year disruption to $734 thousand for a three hour outage occurring ten times per year? The range of costs varied by a factor of ten over the six plants, with the highest cost exceeding $1.5 million for the 3 hour, 10/year case. In a related study, Devine and David Boyd, of ORNL, estimated the cost of standby generation for these six plants at $1 million for 350 thousand kWh or $2.75/kWh to prevent a ten hour outage (8).

Mathtech analyzed the environmental and socioeconomic consequences of a shortage of installed capacity for various duration interruptions to a chlor-alkali plant and a pulp and paper plant. A fifteen minute outage to the chlor-alkali plant was estimated at $18 thousand, or $3.6/kWh. The same outage to the pulp and paper plant was estimated at $55 thousand, or $4.4/kWh. Comparable figures for an eleven-hour interruption were $34.6 thousand ($.16/kWh) and $97 thousand ($.18/kWh) respectively (9). These studies all indicate that a large portion of the total costs are incurred at the onset of even the briefest outage.

Outage costs for commercial customers are more difficult to determine, but disruption costs for capacity shortages have been estimated to range from $2-$10/kWh. Ontario Hydro has reported outage costs for a 20-minute disruption of $1.93/kWh for retail trade, $6.72 for an office building and $174. for large farms (10). A Swedish study reports outage costs of $5.72/kWh for retail establishments and $11/kWh for offices for disruptions of momentary length through 8 hours duration (11).

In spite of the substantially higher costs for disruption in the industrial and commercial sector, it is likely that the effects of power shortages on employment will have to become evident before the emphasis of allocation policies is shifted to maintaining output rather than personal use.

General Impacts and Coping Strategies

The dollar shortage costs cited in the previous examples, while many times the actual price of electricity, are based, for the most part, on isolated disruption experiences. These numbers, taken in analytical isolation, fail to convey the political and economic turmoil likely to result from a chronic wide-spread shortage of electricity. As we look back on the past decade of economic capacity, then, incurs some additional costs--and it is these costs that utilities are being required to bear as penalties for being unable to see the future perfectly a decade ago.

However, too little capacity implies very different risks--the risks of shortages that range from minor inconveniences to lost opportunities for economic growth to the real possibility of social conflict. Shortages pit the poor against the rich, the old against the young and the residential consumer against the industrial producer (14). The ultimate disaster, of course, would be international conflict over limited resources.

Utility decisions today are being influenced by three major uncertainties:

1. Demand Growth - That the future is unknown and unknowable; that an exact match of demand and capacity over long construction lead times is improbable; and that demand growth can change more rapidly than the utilities ability to respond.

2. Financial - That the regulatory process will continue to impose the cost of uncertainty as a penalty to utility stockholders; and that insufficient revenues will be provided to fully recover costs and to provide a return on investment equal to the cost of capital.

3. Environmental - That stringent requirements will be imposed without regards to costs and benefits; thereby inflicting unnecessary costs, reducing competitiveness with oil and gas and demonstrating once again that anything can be made uneconomical.

Under these perceptions, utilities are reluctant to commit today's scarce resources to an uncertain future.

What needs to be done is to restore a regulatory and political climate that encourages rational long-run strategies for electricity production in terms of:

- Compensating utilities for financial risk.
- Recognizing the probability of some mismatch in supply and demand over long and uncertain leadtimes; accepting that mismatch as a cost of uncertainty; and providing as much flexibility as possible to adjust plans to minimize the mismatch.
- Applying stringent cost/benefit criteria to proposed environmental regulations.
- Balancing electricity producing options as a hedge against technological, environmental and fuel supply uncertainties.
- Restoring the economic viability of nuclear power.

Finally, we must recognize that the risk of undercapacity is the risk of social upheaval, while the risk of over capacity is the cost of a few extra dollars in carrying charges in insurance for the continuing operation of our society.

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* Titles are listed for identification purposes only

August 6, 1985

Ms. Gerry Hardy
Committee on Energy & Natural Resources
Dirksen Senate Office Building, Room SD-358
Washington, D.C. 20510

Dear Ms. Hardy:

As we discussed a few days ago, I would like to provide you with our testimony with respect to your Committee's Oversight Hearings on the Potential for Electric Power Shortages in the 1990's. I believe that the information which we have to offer is uniquely different from what other witnesses have provided in that we examine the question of how to treat utility power plant reserve margins. We believe that given the fact that a utility's available operating capacity at any given point in time can be significantly different from its reported "paper capacity", forecasters who conclude that a sufficient supply exists without reviewing the supply plans and operating characteristics of utility power plants may be committing a serious mistake in their forecasts. The recent power outage in Washington, D.C., which occurred due to an unanticipated equipment failure, is exactly the kind of thing which forecasters need to pay attention to. As the country's stock of power plants continues to age and the number of new plants fitted with FGD systems increases, the opportunity for unscheduled outages will also increase.

We have several more detailed papers on the subject of available operating capacity. If, after reviewing our testimony, you would like to receive further information, please feel free to call.

Sincerely,

David L. Lantz,
Research Director

DLL/sy
enclosure

11 S. Meridian, Suite 1005 Indianapolis, Indiana 46204 317-632-3542

TESTIMONY OF

DAVID L. LANTZ

RESEARCH DIRECTOR,

HOOSIERS FOR ECONOMIC DEVELOPMENT COMMITTEE

SUBMITTED TO THE UNITED STATES

SENATE COMMITTEE ON ENERGY

AND NATURAL RESOURCES

JULY, 1985

Thank you Senator McClure and members of the Committee for allowing our organization to present this testimony to you today. The Hoosiers for Economic Development Committee is a statewide public education organization of 15,000 members from a broad range of backgrounds and occupations. We were formed in November 1982 by business, education and labor leaders who share a common concern for Indiana's future and for economic development and job opportunities in the state. Our efforts are funded by contributions from many of our members, from trade associations, business and industry in the state, including the investor-owned electric utilities, and a grant from the State Board of Vocational and Technical Education. One of the issues with which we are concerned is that of providing for an adequate and affordable supply of electricity. We wish to specifically address the issue of how utility generating reserve margins (calculated as $\frac{\text{total capacity - peak demand}}{\text{peak demand}}$) have been incorrectly applied by forecasters.

In recent years, some organizations and individuals, unfamiliar with the complexity of the total picture of electricity demand and forecasts, have referred to an "ideal" reserve margin of 20% above peak demand. They have maintained that a reserve of 20% above peak demand will meet all the needs of electricity consumers. However, what they often fail to point out is that this recommendation stems from a report by the Federal Power Commission (FPC) titled The 1970 National Power Survey. (The Federal Power Commission was the forerunner to the Federal Energy Regulatory Commission.) That study indicated there had been reductions in the nation's electric power reserve margin during the 1960's. In fact, the report indicated reserves fell from 25% in 1963 to 20% in the late 1960's. The FPC in 1970 concluded the 20% reserve figure, industry wide, might be advisable. In other words, the basis for the rule-of-thumb recommendation of maintaining a 20% reserve margin is 15 years out of date. Furthermore, it was made at a time when the largest generating plants were only about one-third the size of today's largest plants.

Since 1970, utility capacity planning has become much more sophisticated. Today, utility engineers do not plan their generating systems on the basis of maintaining a fixed percentage of capacity above forecasted peak demand. Instead, utility engineers utilize a number of sophisticated mathematical models to calculate the least cost level of reliability appropriate for their individual system. One such mathematical formula is the Expected Unserved Energy (EUE). EUE is defined as the long run average energy curtailment per year, due to deficiencies in available generating capacity. EUE is calculated as follows:

$$EUE = \sum_{i=1}^{N} \int_{L=L_{i\,min}}^{L_{i\,max}} \int_{C=0}^{C=L} \frac{8760}{N} (L - C)\, P_{\ell i}(L)\, P_{ci}(C)\, dC\, dL$$

where

N = number of equal length periods/year,
L = system load,
$L_{i\,min}$ = minimum load during i^{th} period,
$L_{i\,max}$ = maximum load during i^{th} period,
C = magnitude of capacity,
$P_{\ell i}$ = probability density function for hourly loads during i^{th} period,
P_{ci} = probability density function for capacity during i^{th} period.

Unless a person has a knack for integral calculus, one would probably spend less than a few seconds looking at the above equation. This leads to the following point: Utility engineers are speaking in Greek. Public policy-makers who seek to establish in statute a definition of excess capacity as any reserve margin over x%, are speaking in Latin. Neither the utility engineers nor the public policy-maker, public-spirited and conscientious though they may be, can understand each other. This is why, for example, a "recommended" reserve margin such as 20% has been widely quoted, yet little understood.

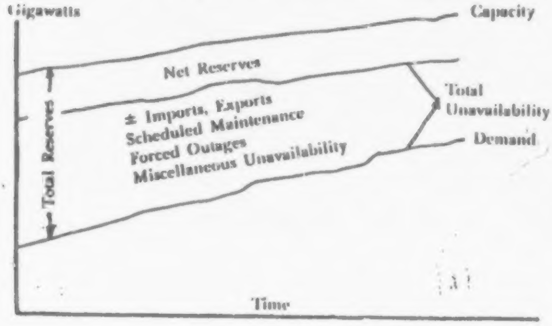
What is needed is an interpreter. Through the following discussion of available operating capacity, such a means of interpretation is presented.

Available Operating Capacity and Net Adjusted Reserve Margins

Presently, when one speaks of "reserve margins," one usually means total reserves as a percentage of peak demand. It is in this context that a reserve margin of 20% is mentioned. However, a more correct way to view reserve margins is to first adjust the utility's total capacity for such things as scheduled maintenance, forced outages, miscellaneous unavailability factors and net exports (imports). After doing so, one arrives at the available operating capacity from which the net adjusted reserve margin is calculated. Exhibit 1 illustrates this relationship between net and total capacity.

EXHIBIT I

CAPACITY, DEMAND, AND UNAVAILABILITY RELATIONSHIPS


Gigawatts
Capacity
Net Reserves
Total Reserves
± Imports, Exports
Scheduled Maintenance
Forced Outages
Miscellaneous Unavailability
Total
Unavailability
Demand
Time

Note: Gigawatt = One million kilowatts.
Source: Earl H. Franklin. "A Fresh Look at Electric Generating Margins," Public Utilities Fortnightly, April 28, 1983, p. 18.

Utilities plan their systems to provide capacity at the point of peak demand. Because of the seasonal nature of peak demand, utilities know that scheduled maintenance during the peak period should be kept to a minimum, while access to electricity imports should be maximized. However, lost capacity due to forced (emergency) outages, environmental derates, or frozen coal piles is less easy to predict. Thus, even with what might appear to be adequate paper reserves, actual reserves at the time of peak demand may be dangerously low. Table 1 presents a case in point.

Table 1: Peak Demand for the East Central Area Reliability Council (ECAR) System, January 21, 1985 (9:00 A.M.)

Total Capacity	90,316 MW	Available Capacity	63,129 MW
Peak Demand	61,358 MW	Peak Demand	61,358 MW
Reserve Margin	28,958 MW (47.2%)	Reserve Margin	1,771 MW (2.9%)

Source: Internal ECAR report: "Operation Panel Report To The Coordination Review Committee On January 21, 1985, System Conditions"

Note: ECAR includes utilities in the states of Indiana, Michigan, Ohio, Kentucky, Virginia, West Virginia and Pennsylvania.

As Table 1 demonstrates, there is a fairly radical difference between paper reserves and actual reserves. Note that ECAR's actual operating reserve margin, after adjusting for capacity unavailability, was only 2.9%. (This is below ECAR's minimum spinning reserve requirement of 3%.) If this is the situation today, what can we expect in the future? The U.S. Department of Energy annually reports forecasts of electric power supply and demand by looking at trends in capacity availability and projecting them into the future. By comparing these projected average capacity availability rates to utility demand forecasts, the DOE estimates forecasts of reserve margins for different areas of the country. Table 2 and Exhibit 2 duplicate the DOE's findings from its report Electric Power Supply and Demand for the Contigous United States, 1985-1994 (published May, 1985).

Table 2

Council Area Adjusted Reserve Margins In Percent*

Summer 1985-1994

Council	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
ECAR	4.3	9.9	7.9	7.2	5.9	5.1	5.7	4.3	4.3	3.3
MAAC	6.3	7.6	8.8	7.5	5.9	4.8	3.6	3.0	1.9	0.3
MAIN	5.2	3.5	9.1	9.0	7.3	5.6	4.0	2.1	2.0	0.3
MAPP	16.0	13.8	11.7	11.8	9.2	6.9	5.4	3.5	1.0	0.2
NPCC	8.9	11.5	14.1	12.6	11.0	9.5	11.8	8.9	9.2	6.9
SERC	12.1	10.8	11.8	10.4	11.1	8.5	9.0	7.6	6.9	5.0
SPP	22.8	24.1	21.1	17.4	13.2	10.3	11.0	8.2	8.4	7.6
ERCOT	3.2	5.5	10.6	9.1	8.4	7.8	7.6	6.7	6.7	6.1
WSCC	17.3	21.6	20.4	20.4	19.1	16.9	16.4	15.7	13.9	13.2

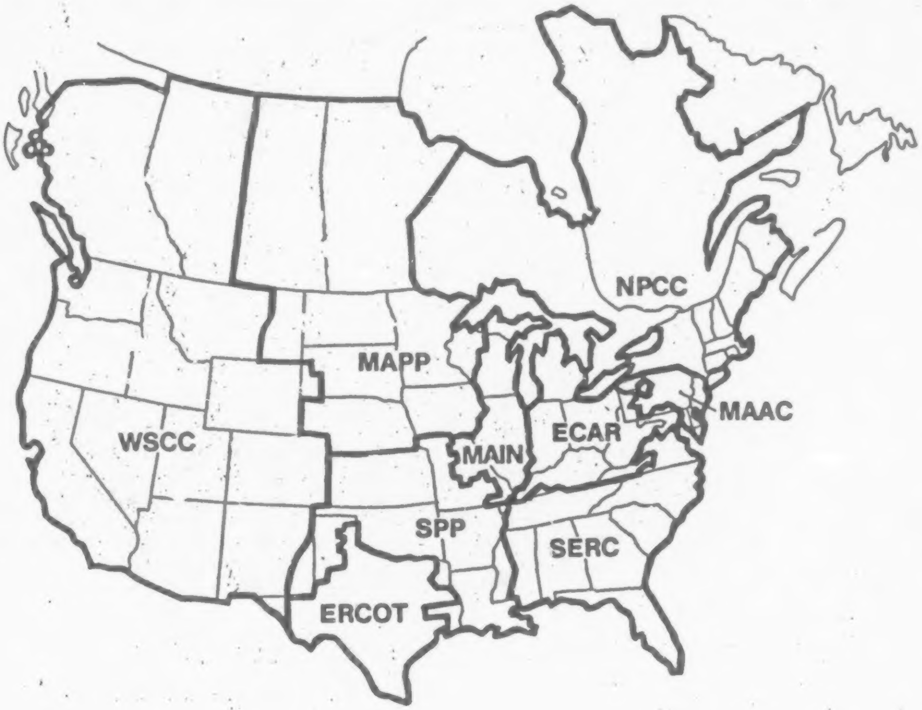
*Installed Reserve Margin, modified by the effects of currently scheduled purchases and sales of capacity and the estimated unavailability of generating capacity due to scheduled maintenance, forced outages and other reasons.

In Table 2, reserves of 5.0% or less have been underscored because at this level it may be advisable to look more closely at the Council situation with respect to available options for purchases of capacity, construction of new units or greater efforts in the direction of conservation.

Source: U.S. Department of Energy, Office of Energy Emergency Operations, Electric Power Supply and Demand for the Contiguous United States, 1985-1994, May, 1985, p. 35.

Exhibit 2

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL



ECAR
East Central Area Reliability Coordination Agreement

ERCOT
Electric Reliability Council of Texas

MAAC
Mid-Atlantic Area Council

MAIN
Mid-America Interpool Network

MAPP
Mid-Continent Area Power Pool

NPCC
Northeast Power Coordinating Council

SERC
Southeastern Electric Reliability Council

SPP
Southwest Power Pool

WSCC
Western Systems Coordinating Council

Source: U.S. Department of Energy, Office of Energy Emergency Operations, Electric Power Supply and Demand for the Contiguous United States, 1985-1994, May 1985, Appendix 1, page 1.

As Table 2 indicates, ECAR, MAAC, MAIN and MAPP are projected to have by the summer of 1992, unsatisfactory adjusted reserve margins. Furthermore, in looking at Table 2, one might ask why the DOE forecast for ECAR's adjusted reserve margin is 4.3% in 1985, when in Table 1 it was only 2.9%? The answer is that the reserve margins reported in Table 2 are averages, while the data in Table 1 are actual numbers.

Sometimes the actual numbers are higher than the average, and sometimes they are below the average.

As potentially serious as the data in Table 2 are, the DOE report provides the following statement made by ECAR:

> ECAR notes in the IE-411 report that the planned capacity margins "are significantly lower, in most instances, than those indicated in last year's response for the corresponding time period. There is a concern that margins even lower than those [reported] will actually be experienced. The reason for the concern is that there exists the potential for either levels of demand higher-than-projected during the period covered by the response, extended outages of coal-fired generating units for retrofitting of flue gas desulfurization equipment, or cancellations or deferrals of capacity additions due to various causes such as changing environmental standards, licensing delays, and the inability to finance [construction]."
>
> (U.S. DOE, Electric Power Supply and Demand for the Contiguous United States, 1985-1994, p. 38)

Mr. Chairman, the Hoosiers for Economic Development Committee is concerned that unless close attention is paid to the issue of available operating capacity, public policy makers will be making decisions based on a faulty interpretation of the data. Such has already been the case in Indiana. For example, a forecast of electricity demand in the Public Service Indiana (PSI) service territory was conducted by the A.D. Little Company. Their study, produced as part of an Indiana Governor's Task Force inquiry into the need for the Marble Hill Nuclear Plant, recommended that PSI (and Indiana in general) maintain only a 15% reserve margin:

> While we acknowledge the possibility that in-depth analysis may support a higher reserve margin for PSI, we have several reasons for recommending that economic studies be based on the lower, 15% figure:
>
>> Economic strains on both PSI ratepayers and shareholders suggest that the company may no longer be able to afford the "luxury" of the traditional standard; rather, a somewhat (and probably comparatively modest) degradation of service should be considered. Evidence from several situations during the energy crisis of the '70s suggests that consumers will accept modestly degraded service when properly explained and fairly applied.
>>
>> PSI is in fact well interconnected and imports are likely to be available, at least to an extent larger than credited in the analyses.
>>
>> PSI's planning makes allowance for equipment which is out-of-service. We believe that during periods of substantial excess capacity, such as PSI has experienced over the last several years, it has made economic sense to let equipment be out-of-service during times of peak rather than taking costly measures to expedite return to service. We believe that PSI would take such measures if its planning showed that a deficiency was likely to result.
>>
>> Although the most recent annual review of the North American Electric Reliability Council("13th Annual Review of Overall Reliability and Adequacy of Bulk Power Supply in the Electric Utility Systems of North America,"August 1983) does not specify a reserve planning criterion for PSI and other utilities in the East Central Area Reliability (ECAR) region, it does state guidelines for two Midwestern areas:
>>
>>> MAPP (roughly, Nebraska, Dakotas, Minnesota, and Iowa) "Each participant should maintain a minimum reserve margin of at least 15% above its annual peak demand."
>>>
>>> MAIN (Eastern Wisconsin, Illinois, and Eastern Missouri) "Present analysis suggests that MAIN members should maintain a minimum installed reserve level of 15% to 20% above peak demand." Commonwealth Edison, listed as a sub-region within MAIN, is also using a 15% margin for its planning purposes.
>>
>> The Reliability Council in Texas, although different in some important respects from the Midwest, is also using a minimum reserve criterion of 15%.

> We recommended to the Task Force that economic analyses of PSI with and without Marble Hill employ reserve margins of 15%. These are lower than those preferred by PSI (25%) as the planning criterion for years in which new capacity will be necessary. (Emphasis added). Arthur D. Little, Inc., Report to Governor's Task Force on Public Service Company of Indiana, December 21, 1983: Recommendations to their Decisions on the Marble Hill Nuclear Power Plant, pp. 19-20.

First, we would note that A.D. Little, by its statement "we acknowledge the possibility that in-depth analysis may support a higher reserve margin" clearly demonstrates that they did not make such an analysis.

Second, because A.D. Little did not perform an in-depth analysis of this issue, they were unaware of the FPC's 1970 Federal Power Survey. Given the fact that the Federal Power Commission published a four volume study on electric power reliability, there is strong evidence to the contrary of A.D. Little's assertion that consumers will not accept degraded service.

Third, as the information in Table 2 demonstrates, imports are not likely to be available from other regions of the country. Again this is contrary to what A.D. Little suggested.

Fourth, and most importantly, A.D. Little quotes from NERC's 13th Annual Review concerning an agreement among the MAPP region electric utilities that "Each participant should maintain a minimum reserve margin of at least 15% above its annual peak demand." Unfortunately, A.D. Little failed to note the fact that geographical considerations play a part in forming this reserve criteria. A.D. Little omits part of the text which is quoted in full as follows:

> Reliability studies and experience of systems in the MAPP area indicate that each participant should maintain a minimum reserve margin of at least 15% above it annual peak demand - its Capacity Reserve obligation - to provide the same level of reliability of power supply experienced in the 1970's. This was a period of

> demonstrated acceptable reliability within the region. Historically, within MAPP, there has been a diversity of about 6% in annual peak demands. This suggests that the MAPP region should maintain a reserve margin of about 22% above the region's coincident peak demand.
>
> (NERC 13th Annual Review, August 1983, p. 36)

Based on the DOE's analysis, it is interesting to note that the year in which MAPP's total reserve margin comes closest to reaching 15% is in 1994, when it is expected to be 15.7%. As Table 2 indicates, however, MAPP's adjusted reserve margin - after considering its available operating capacity - is only .2% in that year. It was largely on the basis of this cursory analysis of reserve margin criteria that the Governor's Task Force concluded that power from Marble Hill would not be needed. Their conclusion was one of the major factors in their decision to recommend cancellation of the plant. Today in Indiana:

1. The junior partner in that project, Wabash Valley Power Association, has declared a Chapter 11 bankruptcy;
2. Public Service Indiana has filed for its second emergency rate hike in less than a year;
3. The electric power supply situation for PSI and Indiana in general is questionable after 1990.

Mr. Chairman, for those interested in forecasting United States electric power supply and demand, it is vitally important that a detailed analysis of available operating capacity be performed. Unless needed capacity is added quickly to the current electric generation capability of America's utilities, the Hoosiers for Economic Development Committee believes that two things could happen:

1. Power outages due to generating capacity unavailability will begin to occur more frequently. Until now, most power outages have occurred due to transmission line failures and transformer outages.
2. Business and industry which might have expanded will, in response to questions concerning capacity availability, be very selective in where they choose to locate. To the extent they choose either to locate overseas, or not at all, this will result in the figurative dimming of America. This is no insignificant possibility. For example, one of GM's location requirements for its Saturn plant is a firm electric power supply of 80 MW, an amount which few, if any, utilities in Indiana could supply by 1990.

On behalf of the Hoosiers for Economic Development Committee, I want to thank the Chairman and the members of the Senate Energy and Natural Resources Committee for allowing us to submit this testimony.

Respectfully,

David L. Lantz,
Research Director
Hoosiers for Economic Development Committee

ROCKY MOUNTAIN INSTITUTE

12 September 1985

Dr. Ben Cooper
U. S. Senate, Room 312
Committee on Energy and Natural Resources
Dirksen Building
First and C Streets, N.E.
Washington DC 20510

Dear Ben:

Our Director of Research, Amory Lovins, is, unfortunately, out of town; but, at his request, I take pleasure in enclosing a section of his recent testimony to the Illinois Commerce Commission. This section documents an increasing decoupling between electric demand and economic growth. The remainder of his testimony, as you will see from the Table of Contents, provides a detailed survey of the hardware, policy instruments, and empirical experience which now enable new technologies to save large amounts of electricity very rapidly, at a cost of below that of just operating any thermal power station. In particular, the full use of today's best electricity-saving technologies would save about three-quarters of all the electricity now used in the United States, at an average direct cost not exceeding about 2 cents/kW-h (1984 $).

We would be glad for this excerpt to be included in the record of the Committee's recent hearings on "When Will the Lights Go Out?"

Our conclusion is that, if people use electricity in a way that saves money, the lights will not only stay on but will do so at lower cost and with utilities able to make more money at less risk. I also enclose for the record Mr. Lovins's recent letter in Science, summarizing recent developments in the utility industry. Since that letter went to press, his analysis has shown, for example, that savings just during the year 1983 in the service territory of Southern California Edison Company totalled about 8.7% of that utility's peak load; the average cost of savings was 0.32 cents/kW-h for the utility's efficiency program (1984 $), $31/kW for the utility's load-management program, and comparable or lower for the state's savings through building codes, appliance standards, etc.

Please feel free to include this letter in the record, too, and to contact us if the Committee has any questions. Full copies of the testimony are available for $50 post paid as Publication Number 85-9. We appreciate your interest and hope that this material will help to contribute depth and balance to the hearing record.

Sincerely,

L. Hunter Lovins
Executive Director

LHL/bb
Enclosures

DRAWER 248. OLD SNOWMASS. COLORADO 81654. (303) 927-3851

BPI EXHIBIT 12 IN DOCKET #82-0855

BPI EXHIBIT ___ IN DOCKET #83-0035

Before the Illinois Commerce Commission

Business and Professional People for the Public Interest, United Mine Workers of America, and Citizens for a Better Environment *Petition to Consider Cancellation of One or More Edison Nuclear Power Plants*	)	**Docket #82-0855**
Energy Conservation Docket--Commonwealth Edison	)	**Docket #83-0035**

LEAST-COST ELECTRICAL SERVICES AS AN ALTERNATIVE TO THE BRAIDWOOD PROJECT

Prefiled Rebuttal Testimony for Petitioners (in #82-0855) and Prefiled Testimony for BPI (in #83-0035)

by

Amory B. Lovins

3 July 1985

ROCKY MOUNTAIN INSTITUTE
P.O. DRAWER 248
OLD SNOWMASS, COLORADO 81654
(303) 927-3851 OR -4178

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Q. What is that?
A. Cream-skimming means buying a cheap efficiency improvement in a way which makes a costlier increment of efficiency essentially unavailable in the future, even though a package of both measures together *would* be cost-effective on the margin. For example, the Northwest Power Planning Council, which has studied this problem extensively, found that converting single glazing directly to triple glazing costs, per kW-h saved, only $0.017 more than converting single to double glazing; but if single glazing has already been converted to double, skimming the cream of the cheapest step, the cost of later conversion from double to triple glazing rises to $0.064/kW-h (all in 1980 $). My point here is not that triple glazing is optimal--in fact, much better and cheaper types of windows are now available--but that the Council quite rightly requires "bundling" of efficiency measures so that the resource represented by costlier increments of efficiency is not permanently lost to the region. Under the Regional Power Plan, consumers receive financing only if they install *all* measures known to be feasible and regionally cost-effective *as a package*. This policy is expected to save about 400 MW in residential retrofits, equivalent *e.g.* to the delivered output of a 679-MWe plant at 0.64 capacity factor.

Q. And what are "direct" costs?
A. For simplicity, I express the costs of efficiency measures, unless otherwise stated, in terms of real resource costs, excluding the cost of money to finance them. This is a good approximation because lead times and paybacks are generally very short, so interest charges have little time to accrue. Similarly, I normally use simple paybacks (capital cost divided by annual value of savings) without discounting or allowing for possible tax effects. Neither, conversely, do simple paybacks reflect any escalation in the real price of electricity, which could make future savings worth more than present ones. I recognize that in principle one should base these sorts of economic comparisons on elaborate discounted cashflow analyses which incorporate all these effects. In practice, however, I have not yet found a case where, on reasonable assumptions, such treatment would change the policy conclusion. I shall therefore use here the more transparent approach of direct costs and simple paybacks, sacrificing a little precision for a lot of clarity.

Q. Can you illustrate how including the effects of financing, discounting, and escalation would not materially change your conclusions?
A. Yes; I shall do so below in the context of a quadrupled-efficiency lightbulb which is one of my *least* cost-effective and shortest-lived options--though still highly cost-effective, however calculated, compared with building and running a power plant. For most of the efficiency improvements I shall describe, payback times are even shorter and the effect of these financial refinements would be correspondingly smaller.

Electricity Demand and Economic Growth

Q. Before immersing ourselves in the technical details of the efficiency improvements you recommend for Edison, let us put your technical analysis in a broader context by exploring the connections between electrical demand and economic growth. Mr. Sillin argues that electrical demand will continue to grow pretty much in step with, if not faster than, the economy, for which he entertains sanguine expectations. If the economy of northern Illinois *does* recover strongly as he predicts, might not electrical demand in Edison's service territory, contrary to your expectations, also continue to grow at roughly the kinds of rates that he (and, at least qualitatively, other Edison witnesses) have projected?
A. Not for more than a year or two at most, for many reasons I shall explain in detail, and not at all if people invest efficiently. Among the most basic reasons is that the faster the economy produces new, more energy-efficient buildings, vehicles, and machines, the sooner the old, *in*efficient stock will be diluted, turned over, or fixed up.

People who project faster economic growth *and* correspondingly accelerated growth in electrical demand are therefore trying to have it both ways: the two are not likely to be consistent with each other.

Moreover, once the constraints on buying efficiency improvements during a recession are removed--such as shorter payback horizons in industry and reduced disposable income in households--wherever efficiency is the best buy, it is *more* likely, not less likely, to be bought rapidly during a recovery. The technical efficiency of U.S. industry, for example, rapidly advanced (with a time lag of up to a year or so) in each of the previous several booms, as managers with more available capital sought the marginal investments which would best keep them competitive. It is now widely accepted among sophisticated analysts of energy demand, such as the Royal Dutch/Shell Group, that rapid economic growth will lead efficiency to improve even faster than it would in a sluggish economy.

I also think Edison's witnesses have misplaced their emphasis on the 1984 rebound of U.S. electric demand. Electric generation in 1984 grew only 65% as fast as real GNP, consistent with the long-term trend (which I shall discuss in a moment) towards the gradual decoupling of electric and economic growth. Since 1984 was a year of unusually rapid recovery after an unusually deep recession, its demand patterns also reflected in part the restart of primary-materials and manufacturing plants that had been shut down during the recession because they were the least efficient plants with the highest operating costs. Such "clunkers" coming off- and online tends to exaggerate both the decline of electric demand in a recession and its early rebound in a recovery; hence to exaggerate doubly the short-term growth rate representing the difference between these two levels of demand.

Similarly, in the early stages of a recovery, electricity-intensive production--say, to make steel and plastics--may increase electric use disproportionately as retailers, anticipating an explosion of pent-up consumer demand for (say) new refrigerators, order new models which must first be manufactured. Months later, however, as inventories are rebuilt and the new refrigerators reach the stores, the early surge of demand for their raw materials abates--and once the refrigerators are actually bought, residential demand may *decline* (if the old machines are scrapped) because the new refrigerators use less electricity than those which they replace. These effects illustrate the perils of overreliance on one or two years' data.

Q. You say that faster economic growth has actually accelerated the improvement of energy efficiency in industry. Have you independently analyzed this effect on demand per unit output, both for total energy and for electricity?
A. Yes. My findings are presented in Figures 1 and 2. Figure 1 provides a vital context for industrial investment decisions: it shows the real prices both of industrial energy (in a use-weighted average of all delivered forms) and of industrial electricity over the past 15 years. Comparing the two curves clearly reveals how increased fuel costs' effect on electrical prices has been both delayed and diluted by fixed charges. In general the years of relatively rapid real runup in electric price nationally were 1973-75 and 1979-82. Naturally, prices in particular regions may differ.

Figure 2 then compares the annual percentage growth in industrial production with the annual percentage improvements in industrial energy and electrical efficiency--*i.e.*, an increase in intensity is expressed as an identical decrease in efficiency and vice versa. (The correlation of increased industrial energy and electrical efficiency with GNP growth is similar but less detailed, since industrial output and GNP are not perfectly correlated.)

Average prices of end-use energy and electricity to American industry

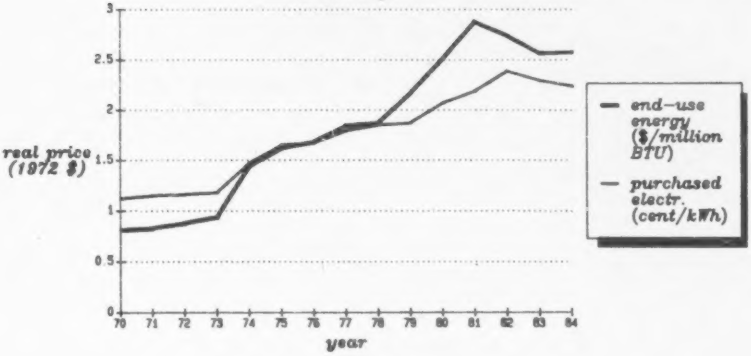

Figure 1

Correlation between growth in industrial output and improvement in the energy and electrical productivity of American industry

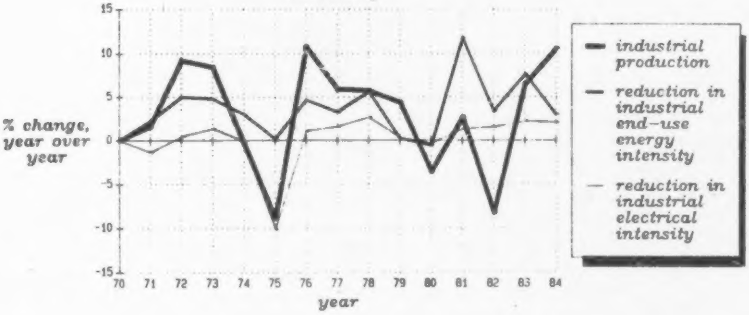

Figure 2

Figure 2 supports the following interpretations:

- In general, gains in both energy and electrical productivity in U.S. industry track industrial growth remarkably well, at least through 1983. (The 1984 divergence in fuel productivity can be qualitatively explained by the decline in real prices.) Figure 2 shows that in good times, industrial managers buy efficiency rapidly so as to keep their competitive edge, while in hard times they usually keep on buying it--only more slowly.
- In general, this response has been most pronounced starting the year after each of the two major price runups, and has become stronger at higher real prices.
- Industrial electrical productivity has risen in eight of the past nine years, and appears still to be rising steadily in response to the 1980-82 real price increases.
- The large increase in electric intensity in 1975, and the small increase in 1980, can probably be ascribed to emergency short-term fuel-switching: industrialists used low-capital-cost, short-lead-time electric heat to keep their processes going for the time being, but within about a year they switched back to longer-term, non-electric, lower-operating-cost substitutes for oil and gas.

These data empirically show the error in Mr. Sillin's assertion that rapid economic and industrial growth imply an increasing intensity of electrical use per unit output in industry. Figure 2 shows that precisely the opposite has occurred. In fact, Edison does not appear fully to accept Mr. Sillin's views either, for on pp. 11-12, Ms. Juracek, having noted the major improvements achieved during 1978-83 in the efficiencies of new appliances, correctly concludes: "There is a natural momentum propelling consumers towards an energy efficient lifestyle, and the historical data reflect this movement."

Q. Is it your opinion, then, that perhaps with temporary and localized exceptions, stable or falling electric demand is consistent with rapid economic growth?
A. Yes: indeed, its economic savings, which I shall describe below, can be essential to *financing* that growth. Whether electrical demand rises or falls depends purely on whether economic activity increases slower or faster than the electrical intensity of that activity. If efficiency gains outpace economic growth, then demand for electricity will fall, regardless of the rate of that growth.

Q. How do you reconcile your view with the well-known historic correlation between electrical demand and GNP?
A. First of all, as discussed below, the electricity/GNP ratio has been falling.

Second, a statistical correlation is never evidence of *causality*. It it were, one might conclude from the likely historic correlation between GNP and, say, consumption of Coca-Cola that in order to have economic growth it is vital to drink more Coke or do any of the other myriad things that correlate more or less well with GNP. Textbooks are full of examples of spurious correlations--such as the one, I'm told, between church membership and alcoholism in New England during the first half of this century.

The fallacy of confusing correlation with causality has already become obvious in the case of the primary *energy*/GNP correlation, which was almost universally believed a decade ago to reveal a sacred and immutable causality. That correlation, however, quickly broke down as the end-use energy content of a dollar of GNP skidded by 26.3% during 1973-82[6]. The energy/GNP ratio is still in free fall by several percent per year: it fell by a further 6.05% in primary terms just during 1982-84[7]. Yet, as I shall show, the United States has barely scratched the surface of how much efficiency is available and worth buying. The savings made so far have chiefly involved the most mundane measures, such as duct tape and caulk guns, rather than the more sophisticated technologies which I shall illustrate presently.

---

[6] Or by about 22.8% if one factors out the GNP growth due purely to higher energy prices; in primary energy terms the corresponding figures are 19.3% and 15.3%.

[7] And by even more if one corrects for falling real energy prices, which decreased energy expenditures and thus depressed GNP. This doubly accelerated rate of decrease in the primary energy/GNP ratio implies a dramatic speedup in the rate of national efficiency gains.

Nonetheless, a dwindling band of observers undaunted by recalcitrant facts--Mr. Sillin prominent among them--continues to aver that electricity is somehow quite unlike total energy in being absolutely essential to GNP, and hence that the two must spiral ever upwards together in a frenetic embrace. This view, reminiscent of the discredited arguments made for inferring causality from the energy/GNP correlation a decade ago, has no more empirical basis than they did.

Simple statistics suggest immediately that any expectation of durability in electricity/GNP ratios is illogical. For example, a typical worker in the service sector uses only *one-fourth* as much electricity as an average manufacturing worker. As GNP shifts increasingly to services, as it is doing in northern Illinois, electricity/GNP (other things being equal) should therefore fall. The very existence of cost-effective ways to use electricity more productively, too, suggests the falsity of a causal link, unless equally cost-effective new uses of electricity are simultaneously found which are so large as to outweigh the savings[8].

Q. It appears that you diametrically dispute Mr. Sillin's views about the rosy prospects for sustaining significant growth in electric demand through faster economic growth, driven as that growth generally is by the service sector and by productivity improvements. Can you suggest ways to test his opinions empirically?

A. Yes--most convincingly through sector-by-sector analysis. The next part of my testimony will do this by presenting detailed engineering/economic facts bearing on *future* demand. But let me start here with *historic* demand, for past consumption data should indicate whether there is some observable basis for Mr. Sillin's assertion (pp. 25-27) that the "new and more modern equipment" which will be installed throughout the economy as a result of faster economic growth "will be more electricity intensive than in the past," both in industry and in buildings. In reality, that assertion is utterly at variance with the actual data.

The Department of Energy's Electricity Policy Project reported in June 1983[9]:

- During 1973-80, U.S. electric use per residential customer rose by only 0.80%/y[10], just a seventh of its 1960-73 rate (p. 3-24). Three-fourths of the sectoral demand growth was due not to more intensive use but to more households (*id.*). "Although heat pumps and air conditioners continued to penetrate their respective markets, such substantial increases in usage were offset by end-use efficiencies achieved elsewhere in this sector" (*id.*, pp. 3-24 and 3-25). EIA survey data even revealed (*id.*, p. 3-71) a sharp decline--by *21%*--in electrical consumption per electrically heated household during the two-year interval 1978-80, while use per non-electrically-heated household stayed virtually flat[11].

---

[8] A few such uses have been found, mainly in industry, but they are very small compared with the savings: complete robotization of all American industry, for example, would probably increase national electric demand by only a few tens or hundreds of megawatts.

[9] "The Future of Electric Power in America: Economic Supply for Economic Growth," DOE/PE-0045; see also "Need for New Powerplants," hearing record of 7 February 1984, Subcommittee on Energy Conservation & Power, Committee on Energy & Commerce, USHR, Serial 98-104.

[10] This figure may be smoothed or weather-corrected, since EIA sales data combined with EEI customer data yield 0.98%/y compound.

- During 1973-80, electric consumption per commercial customer grew by only 1.25%/y, a fifth of the 1960-73 rate (*id*., p. 3-27). (In 1981 it started falling.) Again, 62% of sectoral demand growth came from more floorspace, not from more kilowatt-hours used per square foot (*id*.).
- During 1975-80, electric demand per unit of industrial production *fell* by an average of about 1.03%/y (*id*., p. 3-31; the actual value, according to EIA data, was 1.076%/y compound). Moreover, "during periods of economic expansion, [industrial] output tends to grow slightly more rapidly than electric purchases [*i.e*., electrical productivity increases], while, during economic downturns, growth in electric purchases slows somewhat less than growth in output" (*id*.)--consistent with my Figure 2 above.

Since 1980, all these trends have accelerated. For the total electric utility industry, the 1983 EEI *Statistical Yearbook* (p. 51) shows 1980-83 demand per customer *down* 2.2% in the residential sector and *down* 1.7% in the commercial sector, despite a simultaneous growth of 4.1% in real GNP and a corresponding increase in real personal income[12]. This empirical decline in the aggregate electrical intensity of buildings is consistent with the observed rapid improvement in the thermal and lighting efficiency of all kinds of new and most kinds of existing floorspace over the past few years. In industry, too, the electricity consumed (according to EIA) per unit of production *fell* by an impressive 7.01% during 1980-84.

With national population growth rates already around 0.9%/y and declining towards about 0.7%/y in the '90s; with demand per house, per commercial customer, and per unit of industrial production essentially flat during the economic growth of the past six to ten years; and with all three of these sectoral intensities generally *falling* over the past few years; where, then, is Mr. Sillin's sustained, substantial growth in electric demand supposed to come from? He dismisses this awkward question by airy references to the "relationship" between electricity use and GNP. A closer look at the actual data, however, again shows that the facts do not support his theory--nor for that matter the implicit "relationship" which drives Edison's econometric forecasting models.

For decades until about mid-1977, the electricity/GNP ratio--the aggregate electrical intensity of the U.S. economy--rose, at gradually decreasing rates, as real electric prices fell. This intensity increased altogether by 2.7-fold during 1949-77. Since then, however, as rising real prices took hold, the ratio has stabilized and fallen, as Figure 3 shows--the start of a long-term price response that will take upwards of a decade to run its course after any price increases, including recent and prospective ones. The

---

[11] Further underscoring consumers' disquiet with rising residential electric prices--they rose, on average, by 27.2% above the Consumer Price Index or 40.8% above monetary inflation during 1973-84--the number of new housing starts using electric heat also fell by a third during 1970-81. EIA surveys also show that during 1981-83 the absolute market share of electric heating in occupied U.S. housing units fell for the first time since 1950.

[12] Preliminary 1984 data supplied to me by EEI show 1980-84 sales per customer down 0.8% residential and up 1.2% commercial; the one-year commercial rise in 1984 is probably due to increased store hours and other behavioral effects. Real GNP grew 11.2% during 1980-84.

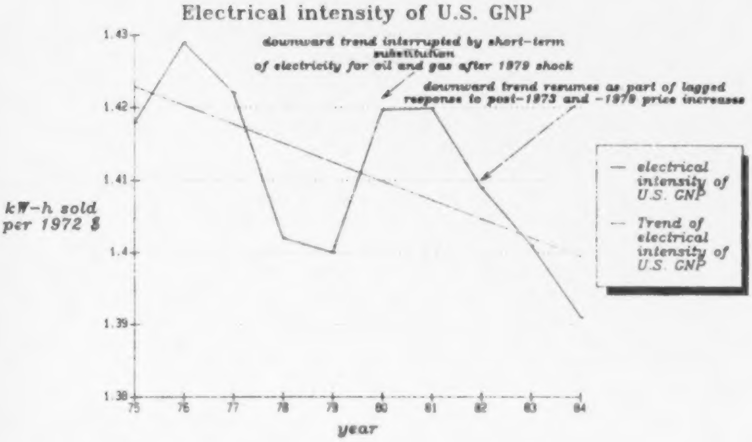

Figure 3

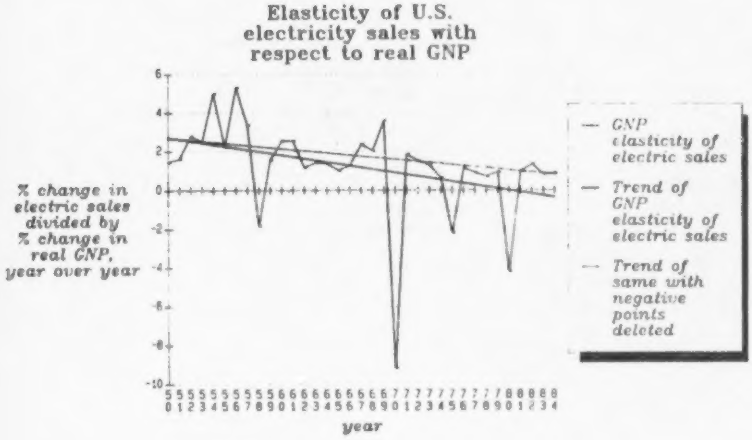

Figure 4

electricity/GNP ratio has already fallen in six of the past eight years, dropping by 0.6% or more in each of the past three years; its 1984 level was 2.6% below its 1976 annual high (its quarterly high was in mid-1977).

An even more sensitive form in which to examine historic trends is the ratio of annual increases in electrical sales to annual increases in real GNP. Figure 4 plots this elasticity for 1949-84. Its general downward trend, represented by the superimposed linear-regression trend line, is unmistakable. Even if the anomalous years with negative values (where electrical sales and GNP moved in opposite directions, as they recently did because of short-term fuel-switching after two oil shocks) are removed, the alternative trend line shows a steady drop which passed below unity several years ago. The actual annual value of the elasticity has been less than unity for seven of the past eight years, averaging 0.94 during 1979-84 and 0.87 during 1982-84. Figure 4 shows, then, that the values greater than unity which Mr. Sillin proclaims will obtain in the future have not actually been sustained since a decade ago.

Indeed, Mr. Sillin's contention of a 1.0+ future electricity/GNP elasticity is hard to reconcile with the data which he and John Siegel of the Atomic Industrial Forum published in their February 1985 "Update of the Siegel-Sillin *Electric Load Forecast*." There they stated that the five-year moving average of the ratio of electrical output [growth] to GNP [growth] "averaged .86 the past four years," falling almost continuously as follows:

1976	1.7
1977	1.5
1978	1.3
1979	1.2
1980	1.0
1981	0.95
1982	0.86
1983	0.80
1984	0.83

--a trend hardly consistent with the increase to 1.0 or more which Mr. Sillin is suggesting in this proceeding.

Q. Don't your conclusions about a continuing and accelerating increase in the national efficiency of using electricity depend on its real price's increasing?
A. No; that could drive efficiency faster, but is not required for it to proceed vigorously, because the efficiency improvements I shall describe generally cost far less even than *present* electricity prices. I do, however, disagree with Mr. Sillin's assessment of prices, starting with historic ones. Real prices in 1983, according to the 1983 Edison Electric Institute *Statistical Yearbook*, fell by about 0.2%[13], not by 1.5% as Mr. Sillin states at p. 21 of his testimony or 2% as he stated in his and Mr. Siegel's February 1985 "Update." I believe he is similarly exaggerating the likely decline of real electricity prices in the future.

Although Mr. Sillin projects a possible price decline of 10-15% during 1982-90, the major DOE study cited earlier (DOE/PE-0045), despite assuming that both power plants and money will be considerably cheaper than they actually are, forecast average U.S. real electric prices to rise by about 40% during 1982-2000 (p. 3-89)--owing largely to the utilities' nearly quadrupling their real asset base. Similarly, R. L. Itteilag of the

---

[13] That is, 3.63% nominal rise less 3.84% GNP implicit price deflator from DOE/EIA's "Annual Energy Review 1984" published April 1985. Mr. Sillin might have been using data from some selected subset of the utility industry; EIA (id.), for example, states that weighted-average real prices of electricity from selected $100+M/y Class A utilities fall by about 1.4% in 1983.

American Gas Association[14] forecasts that nuclear completions and cancellations will drive average U.S. electricity prices to 36% above real 1983 levels by *1990*.

Mr. Sillin's declining real prices are also hard to reconcile with most utilities' calls for increased rates of return. To first order, if demand rises 3%/y during 1985-90 while real prices fall 10-15% during 1982-90, gross utility revenues (quantity times price) will rise by only about 1.4-7.4% real from 1985 levels, despite 15.9% greater output. This will require very large drops in fuel prices to maintain even current returns on a rapidly rising ratebase.

On a more micro level, Mr. Sillin also assumes as correct Edison's expectation that its own real prices will fall after 1987, without noting that this assumption depends critically on a low price elasticity of demand: if, as my efficiency analysis will suggest, Edison is pricing itself out of the market, the company could instead be poised on the brink of an uncontrollable price spiral whereby each rate hike triggers further demand reductions, requiring still higher prices in order to pay fixed charges. For example, suppose that Edison's predictions of a real price increasing by only 6.6% in 1985 and 1.2% in 1987, but otherwise *falling* by 3+%/y in 1989-94, prove too optimistic (would Edison be willing now to stipulate to those predictions as ceilings for future rate increases?). If this occurred, *e.g.* because construction cost more or price elasticity of demand were stronger than Edison expects, then demand will grow still less, prices will have to go still higher, demand will grow still less, and so on--perhaps into the "spiral of impossibility" which many utilities have good reason to fear. In other words, the relationship of increased revenue to increased price depends very sensitively on price elasticity of demand, but Edison cannot know whether its projections of the prices and sales needed to meet its revenue requirements have correctly guessed the long-run elasticity. A small error in that guess can lead to a revenue shortfall large enough to turn falling into rising real prices.

Q. Mr. Sillin's testimony emphasizes the historic increase in electricity's share of all delivered energy. Do you agree that is a valid argument for supposing that this share, and absolute electrical demand, will continue to increase?
A. No, for the same reason that the high electricity/GNP ratios of the 1950s and 1960s do not imply that in the future the same ratio will be large or even will increase at all. What matters is again how well electricity can compete with all other ways (including end-use efficiency) to provide the same energy services.

Mr. Sillin's implication that an increasing electrical *share* implies increasing electrical *demand* is also fallacious. Even if electricity's end-use market share did continue to increase, that does not necessarily imply an increase in absolute demand for electricity, because electricity could well have an increasing share of a dwindling market. Most long-term international studies of energy efficiency show exactly this effect. Our German analysis cited earlier, for example, found that an increase in the electrical share of all end-use energy from 7% to 17% was consistent with a 68% *decrease* in electrical demand (for the same GNP). In fact, such behavior *has already occurred* in the United States: during 1981-82, electricity's share of all end-use energy rose from 13.0% to 13.3%, while the absolute demand for electricity *fell* by 2.8%--simply because end-use energy meanwhile fell by 5.1%. A similar discrepancy between market share and absolute demand is evident for 1979-83: electricity's end-use market share rose by 21.3%, but electric demand rose by only 3.8%, because the total end-use demand of which electricity had such a rapidly rising share fell by 14.4%.

Q. Do you likewise dispute Mr. Sillin's contention that electrical demand will increase because real prices will be more stable for electricity than for, say, oil and gas?
A. Yes. Even supposing this to be true--and in light of today's best thinking about fuel *vs.* power prices its truth for the next decade or two is far from self-evident--the relative prices or price trends of electricity and direct fuels do not much matter if *both*

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[14] "Public Utilities Fortnightly," 21 March 1985, pp. 35-40, using updated costs and 10%/y real returns.

are unable, as my analysis shows, to compete with efficiency improvements. That is, their own-price elasticities of demand will swamp their cross-elasticities.

Q. Evidently you foresee a gradual decoupling--a slowly widening gap--between electric growth and economic growth. Is there any national precedent for such a development?
A. Yes: closest to home, the dramatic decline, by 34.6% during 1973-84, in the oil and gas intensity of the U.S. economy. This was done using relatively rudimentary technologies. It can and, I believe, will happen for electricity too, because *both* these forms of energy must compete, but are unable economically to compete, with efficiency improvements.

Q. But it hasn't *yet* happened nationally to anywhere near that extent for electricity. While the ratio of total energy use, or of non-electric energy use, to GNP has been declining steadily since the early 1970s, hasn't the *electricity*/GNP ratio been more stable?
A. Yes, and it is important to understand how far and why.

U.S. electricity sales during 1973-84 rose 101.9% as much as real GNP[15]. But throughout 1973-84, as Figures 3 and 4 show, the electricity/GNP correlation was continuing to loosen: in 1984, in a booming economy, the electricity/GNP ratio hit its lowest annual level in a decade (Figure 3). Electric sales grew more slowly than GNP in six of the past eight years--of late only 0.8-odd as fast, with this ratio falling rather steadily[16].

This historic but weakening electricity/GNP correlation will in my opinion be a short-lived artifact: I expect electricity soon to start emulating the past decade's energy/GNP decline in a lagged response to the real price increases of the past twelve years.

Q. Why do you expect that to happen 10-15 years *after* the correlation between direct-fuel demand and GNP broke down?
A. For at least eight persuasive, but often overlooked, reasons:

1. Power plants take so long to build that, with rolled-in pricing (exacerbated by normalized accelerated depreciation), it takes many years for marginal costs to work fully through into average prices--far longer than for most increases in direct-fuel costs.
2. Higher fuel prices hit consumers with full force, whereas their impact on electricity prices is diluted by high fixed charges.

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[15] That is, the ratio of 1984 to 1973 sales, divided by the ratio of 1984 to 1973 GNPs, was 1.0188--the ratio of one absolute growth factor to another. On pp. 20-21 of his testimony, Mr. Sillin instead describes the ratio of growth percentages, which in the case just mentioned would have been 1.105 and in the case he mentions, that of the 1973-82 period, was 1.21--compared with only 1.0321 for the ratio of growth factors. That is, my ratio describes the change in electrical intensity; his, the GNP elasticity of electrical sales, which is a far more volatile quantity, depending as it does on the ratio of two small numbers. This distinction can be highly misleading if not understood.

[16] Further, with a significant part--probably at least 15%--of all economic activity in the "gray economy," which is not counted in GNP statistics and is growing much faster than GNP, a constant electricity/GNP ratio or a unitary electricity/GNP elasticity would actually indicate a falling ratio of electricity use to total economic activity, both that counted in and that omitted from GNP.

3. Electricity is apparently the most heavily subsidized form of energy[17].
4. Many utilities still have, or have only recently abandoned, promotional tariffs, cross-subsidies, and other programs to promote demand--practices which are far less common in sales of direct fuels.
5. More electricity-using than fuel-using equipment is bought by people who will not use it and do not care about its running costs. Most people, for example, buy their own cars and study the mpg sticker; most homebuyers look at previous utility bills; but only a minority of major household appliances are bought by their users, most commercial HVAC equipment is chosen by a mechanical engineer, and over 90% of home heating systems are specified by contractors. Thus the electricity-using equipment being bought is more isolated from market forces favoring efficiency than are the fuel-using devices being bought.
6. In particular, about half the new houses being built in the United States are electrically heated--a major source of projected demand growth--because many builders think it reduces their upfront cost[18].
7. Although the key *fuel*-saving measures--insulation, weatherstripping, better cars, plugging steam leaks, etc.--are well-known and widely available, many of the most important types of *electricity*-saving technologies have only come on the market in 1982-85, so few people have yet heard of them.
8. Electricity is especially sensitive to shifts in composition of output as (for example) services displace heavy industry, aluminum production moves offshore, and the steel industry contracts--a point to which I shall return.

Q. So for these reasons, do you expect that within the next few years the electricity content of a dollar of real GNP will start to fall even faster than the 0.66%/y average rate at which it has fallen for the past three years?
A. Yes. Of course, how soon and how steep that fall is will depend on public and private policy--in essence, on how well jurisdictions like Illinois approximate the workings of a competitive free market in energy services. For it is a basic premise of my testimony that *demand for electricity is not fate but choice. Demand is not a predetermined outcome to be prophesied by reading the entrails of forecasters, but rather a variable to be influenced in accordance with policy goals.* Demand is therefore not to be forecast so much as managed. Demand can be artificially inflated, and has been, or it can be encouraged to adjust itself smoothly to economically efficient levels. For every task, there is an amount of electricity (as of any other factor input) that will get the job done at minimum total cost. My analysis and recommendations seek this right amount.

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[17] The preliminary results of a comprehensive analysis done under my supervision by H. Richard Heede indicates that in FY1984, Federal subsidies to energy supply, conservatively exceeding $46 billion, went 32% to fission, which met 1.5% of the end-use energy-service needs; 29% to oil and gas, which met 52% of those needs; 24% to fossil-fueled central electric generation, which met 8% of those needs; and 11% to efficiency and renewables, which met 17-31% of those needs. In all, total electrical supply received 75% of the subsidies while meeting only 11% of the energy-service needs, whereas direct fuels got 31% of the subsidies and met 74% of the energy-service needs (the remaining 15% being met by efficiency gains). Thus on average, electricity was about 16 times as heavily subsidised, per unit of energy supplied, as direct fuels (counting electricity at its heat value, 3,413 BTU/kW-h). See "A Preliminary Analysis of Federal Energy Subsidies in FY1984," invited testimony to the Subcommittee on Energy Conservation & Power, Committee on Energy & Commerce, USHR, 19 June 1985, RMI Publication #85-7.

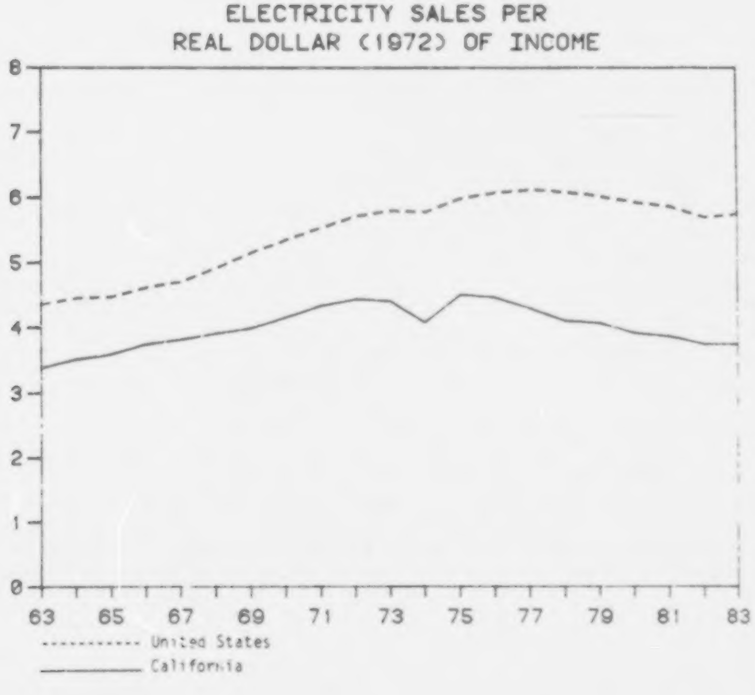
[18] And thus makes the house more saleable in times of high mortgage interest rates. In reality, however, later mortgage default looms when utility bills exceed mortgage payments: lenders can get stuck with houses nobody can afford to live in. And not only would the house arguably cost less to build if superinsulated with today's best techniques so it can be all-electrically heated with a couple of light bulbs; worse, the competitor for the buyer's getting a mortgage is the enormous financing which the utility must undertake to supply a normally inefficient all-electric home. I shall later suggest a remedy.

Q. You suggested earlier that utilities and regulators in some other jurisdictions have already begun to follow this advice. Can the results of their policy initiatives be seen yet in an observable decoupling between electrical and economic growth?

A. Yes. The clearest case, because concerted least-cost initiatives began there earliest, is that of California. The California Energy Commission describes this by reference to the graph reproduced below, which shows *a decrease of about 17% (2.3%/y compound) in the electrical intensity of the California economy during 1975-83*. The Commission describes the results and prospects in the following terms[19]:

> Figure 2-1 shows electricity consumption [in thousands of BTUs delivered] per dollar of personal income for the nation and for California over the period 1963 to [1983]....Through the 1960s and early 1970s, the pattern of change was similar, although California's electricity use was lower due to milder climate and a less energy-intensive industrial mix. In the mid-1970s, the trends diverged, with California showing decreased [electricity]...use per dollar of personal income. Several factors

Figure 2-1



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[19] CEC (Sacramento), "The 1985 California Electricity Report," P106-85-001, main volume, May 1985, pp. 13-15.

> caused this change: (1) consumer response to electricity rates rising more rapidly in California than in the rest of the nation following the 1973 oil embargo, particularly in the industrial sector; (2) shifting composition of California's economy to less energy-intensive industries and more services; (3) conservation programs established by the CEC, electric utilities, other government entities, private citizens and commercial/industrial firms.
>
> The Commission's forecasts indicate that this trend of decreasing electricity usage per unit of economic activity will continue: the number of BTUs [of delivered electricity] required to produce a dollar of personal income will decrease from the current [1983] level of 3,750 to 2,970 by 1996 [a 21% decrease], and to 2,620 by 2004 [30% below the 1983 level]. The increased impacts of existing conservation programs such as the building and appliance efficiency standards, expected future electricity rate increases, and continued shifts in the composition of the California economy will account for this desirable trend. Additional, cost effective policy actions could reduce electricity consumption per unit of economic activity even further. The continuation of this trend again demonstrates that there is no fixed relationship between economic growth and the electricity needed to accommodate that growth. In other words, it is possible to increase the standard of living and the availability of goods and services, while using less electricity.

Thus, over the next 19 years, Governor Deukmejian's Commission firmly expects the electrical intensity of the California economy, the nation's most dynamic, to fall to *42% below its 1975 level*, just through market forces already operating and programs already in place--with further cost-effective reductions available if desired. As I shall show below, the Commission also found that California's electrical sales will grow only 52.8% as fast as Gross State Product through 1996, decoupling even further thereafter.

Q. Do you think Edison is paying enough attention to the opportunities for a similar adaptive process, whether market- or policy-driven or both, in Illinois?
A. No; neither do most utilities elsewhere. They therefore risk repeating the errors of the early 1960s, when many utilities underforecast demand and were caught short. They erred in three ways: they paid little attention to end-use markets; they underestimated price elasticity of demand in a period of declining real price; and in particular they underestimated the efficacy of entrepreneurs who were out in the marketplace selling comfort and convenience--which in those days meant air conditioning. Suppose that a utility makes the same mistakes today: not doing detailed end-use analysis, underestimating price elasticity in a period of *rising* real price, and underestimating demand for comfort and convenience--which nowadays means greenhouses and weatherstripping. By making exactly the same mistakes as two decades ago, a utility today could *over*estimate demand and *over*build.

Q. How do you recommend that utilities avoid this danger?
A. By striving with all their hearts to achieve least-cost investments for both themselves and their customers. This will require a mix of several types of actions, depending on local conditions, what skills the utility has, and how its customers perceive it. The main ingredients of the mix should include public information, education of particular individuals and groups, purging of institutional barriers, rate reform to achieve truthful prices, psychological leadership, financing least-cost investments on the customer's side of the meter, economic incentives, and mechanisms for making a market in saved electricity.

Q. Will your testimony treat each of these types of actions?
A. Briefly, and I would be glad to amplify it orally before the Commission or in meetings with the parties. The portion of my testimony dealing with implementation, however, will concentrate on financial and economic mechanisms, as these are perhaps the least familiar topic and are most relevant to the Braidwood decision.

Q. You have now made clear your views on the relationship between electrical demand and economic growth in general, with reference to historic patterns. Let us therefore move on to the factors which can influence future demand and can provide the elec-

tricity/economy decoupling you expect. How will you organize your discussion of these factors?
A. I shall describe the nature, performance, and cost of the more important electricity-saving technologies; illustrate their application to Edison's service territory in the context of its evolving economic trends; explain why that application is consonant with Edison's strategic-planning imperatives; describe how the hardware can actually be financed and put in place in a timely and reliable fashion; and lastly compare its economics and reliability with those of completing Braidwood.

Q. Can you characterize the basic differences between your view of these substitutes for Braidwood and Edison's view of them?
A. It is not clear from the testimony of Edison witnesses and from the company documents I have examined whether Edison is even aware of many of the substitutes I shall describe. Edison's level of understanding of modern electricity-saving technologies seems at best sketchy. Nor does Edison appear to have done any serious analysis of how the full range of electricity-saving options can advantageously apply to its load patterns. This mindset might be explicable in terms of an institutional fixation on the construction program, but I shall suggest that it does a disservice to Edison's ratepayers and investors. So large are the stakes that it is worth examining the new electricity-saving opportunities in considerable detail, and I shall do so next.

Electricity-Saving Technologies

Q. Please give some salient examples of the efficiency improvements which you believe can greatly reduce future electrical needs.
A. Certainly. The following examples are not exhaustive, but should give the flavor of how rapidly new ways to save electricity are emerging. I shall describe almost entirely ways to *save* energy and power rather than to *shift* loads through load management, whether by tariffs, storage, or controls, although there has also been gratifying progress in such load management techniques.

Lights. The Electric Power Research Institute (*EPRI Journal*, June 1984, pp. 6-15) states that "According to recent estimates, a grand total of 50% of the 420 billion kWh a year used for [U.S.] lighting could be saved through energy-efficient strategies, all without imposing any hardships on productivity, safety, or esthetics." As I shall show, the latest technologies permit even larger savings.

For the past few years in Europe, and starting in 1984-85 in the United States, several leading manufacturers have been marketing compact fluorescent light bulbs, most of which fit the standard screw-in sockets used by the conventional incandescent bulbs[20] which use about 42% of U.S. lighting electricity. The best of the compact fluorescents contain miniaturized high-frequency electronic ballasts and folded tubes with "tristimulus" phosphors, which are tuned to the eye's red, green, and blue retinal cones for nearly perfect color rendition. The resulting bulbs are about four times as efficient as ordinary incandescent bulbs and last 10+ times as long.

Philips of The Netherlands (Norelco in the U.S.) began marketing "SL" and "PL" bulbs several years ago in Europe and in 1984 in the United States. North American Philips Lighting Corporation bought the entire U.S. Westinghouse lamp-making capacity in March 1983 to make them faster. Anyone can now buy the bulbs through lighting stores and Philips outlets in most cities, although Norelco is not currently promoting the bulbs outside the commercial sector.

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[20] These have also improved significantly through better filaments, special envelope coatings, halogens, increased argon filling, krypton filling, and elliptical and other reflector designs which (as in GE's ER series or certain Duro-Test models) focus well in front of the fixture, reducing light-trapping and heat buildup. This discussion, however, deals instead with more fundamental and effective innovations which replace incandescent lamps outright.

Letters

The Electricity Industry

Mark Crawford (News and Comment, 19 July, p. 248) echoes the power industry's warnings of impending electrical shortages, but omits the best ways to ensure abundance.

Few utilities take electrical efficiency seriously. All their forecasts of demand assume several-year-old technologies for wringing more work from each kilowatt-hour, and many are 10 years behind. Yet most of the best such technologies have been on the market for less than a year. Collectively, they now cost a third as much as they did 5 years ago, yet can save twice as much electricity; fully used, they can quadruple U.S. electrical productivity (*1, 2*). Measures that save 80+ percent in commercial lighting on retrofit (90+ percent in new buildings), 80+ percent in fully equipped all-electric houses, and about 50 percent in industrial drivepower all pay back in a few years (*1, 3*). Our own research center uses no heat and 5 to 10 percent the usual amount of electricity (*4*), repaying the capital cost of those savings in 10 months.

Utilities have meanwhile developed new ways to implement and finance electrical savings, including loans, rebates, and generous payments for whatever customers save. By recognizing that demand is not fate but choice, smart utility managers can and now do save electricity faster than they could build a coal or nuclear plant and more cheaply than they could operate one, even if building it were free (*1, 5*). Thus abandoning a giant plant even after spending several billion dollars on it, and buying efficiency instead, can save billions of dollars—enough to repay the investors while lowering the rates (*1, 6*).

Utilities that promote end-use efficiency can make more money at less risk. They save operating, construction, and replacement costs, and reduce the uncertainty of demand and hence the risk of overbuilding. They can even earn a spread on financing. Conversely, utilities that ignore the efficiency revolution risk obsolescence. Now that electricity costs an order of magnitude more than efficiency, customers want less electricity and more efficiency. If utilities instead raise prices to try to pay for expensive new plants, sales may drop so dramatically that long-run revenues fall.

Utilities can make future demand more uncertain—as they did by raising prices to finance huge new plants that, ironically, were meant to "insure" against uncertain demand. Or utilities can reduce uncertainty by encouraging and enabling customers to buy efficiency. Further, to minimize the cost of hedging against residual uncertainty, successful utility managers acquire only options that are small, fast, and cheap. Rather than playing "You Bet Your Company" that their forecast of demand 8 to 15 years ahead is right by committing billions to a plant which takes that long to build, they seek to reduce risk and uncertainty to an affordable level.

Under this central imperative of modern utility management, the forecast-and-build methodology that Crawford describes is obsolete—replaced by a wide array of flexible options that can be relied on to meet demand essentially ad hoc (*7*). That is the main reason why only a few central power plants, none with a capacity of more than 600 megawatts, were ordered between 1982 and 1984. It is why central-station orders between 1981 and 1984, less cancellations, totaled −65 GW, while new orders (*8*) were placed for 25 GW of cogeneration and 20+ GW of small hydro, wind power, and other renewables (*9*). The booming market in small, fast power plants with affordable risks is nearly compensating for the collapse of the market in huge, slow plants with intolerable risks; and efficiency, where tapped, is more than making up the difference.

For example, a least-cost investment strategy has reduced electricity sold per real dollar of California's Gross State Product by about 17 percent between 1975 and 1983. This ratio is officially projected to fall by another 30 percent between 1985 and 2004 (*10*) just from existing market forces and policies (such as tighter building codes and appliance standards). That will eliminate the need for 12 GW of peak capacity by 1994 (16 GW by 2004), with another 7 GW of 1994 savings under consideration and more available. Moreover, by the end of March 1985, with 37 GW of peak demand and 10 GW of in-state utility-owned hydro and geothermal capacity, California had been firmly offered 20.3 GW of independent small power production (*11*). Entrepreneurs were offering an additional 9 GW per year until, this April, the resulting power glut forced suspension of new contracting. Yet two dozen other states and provinces, undeterred, all hope to sell California their surplus power simultaneously.

National trends are less mature, but moving the same way. Cogeneration rose from 5 percent to 7 percent of electric output just in 1984, and small power commitments now cover, for example, more than 22 percent of Maine's and 14 percent of New Hampshire's peak loads. Between 1982 and 1984, U.S. electric demand grew only 0.87 times as fast as gross national product, with this elasticity continuing its 30-year decline. (Most prophets of power shortages project an elasticity of 1.0 or more, but California projects 0.53 through 1996.) In the past 4 years, U.S. electric sales per real dollar of industrial output have fallen 7 percent, with demand per residential and commercial customer remaining nearly constant. Yet this gradual decoupling of electric from economic growth, proceeding most quickly when economic growth is fastest, has occurred despite many barriers to efficient investment. Among these was $30 billion of federal subsidy in fiscal year 1984—per unit of energy, eleven times the subsidy to direct fuels and at least 48 times that to energy efficiency (*12*).

AMORY B. LOVINS
Rocky Mountain Institute,
Post Office Drawer 248,
Old Snowmass, Colorado 81654

References and Notes

1. A. B. Lovins, *Least-Cost Electrical Services as an Alternative to the Braidwood Project* (Illinois Commerce Commission Exhibit BPI-12, Docket 82-0855, 3 July 1985; available from the author).
2. The average direct cost of these measures is under $0.02 per kilowatt-hour saved in 1984 dollars.
3. For motors, see also A. B. Lovins, *Scoping Calculation of Electrical Savings in a Pulp-and-Paper Mill*, June 1985; available from the author. The household norm referred to is for San Diego in 1984.
4. It uses 1.3 average watts per square meter, two-thirds of which is for office equipment.
5. See also A. B. Lovins, "Saving Gigabucks with Negawatts," *Public Util. Fortn.* 115 (No. 6), 19 (21 March 1985); *ibid.* 115 (No. 8), 12.
6. Similarly, saved operating costs from end-use efficiency can pay for abating acid rain while lowering electric rates.
7. A. Ford, in *The Future Market for Electric Generating Capacity: Technical Documentation* (LA-10285-MS, Los Alamos National Laboratory, Los Alamos, N.M., March 1985), chapter 2, pp. 77–181, shows that reduced risks make it worth paying up to four times as much per kilowatt for an option that takes 5 years to build as for one that takes 15 years. Options with a 1- or 2-year lead time are even more valuable.
8. Including firm letters of intent.
9. Roughly a quarter of the cogeneration was also renewable, burning mainly forestry wastes. By 1984, renewable sources provided 10 percent of total U.S. primary energy—the fastest growing part, outpaced only by savings. Between 1979 and 1983, the United States got more than 100 times as much new energy from savings as from all net expansions of energy supply.
10. *The 1985 California Electricity Report* (P106-85-001, California Energy Commission, Sacramento, May 1985), pp. 12–15. Additional cost-effective savings are stated to be available if desired.
11. Mostly renewable, with an average project size of 12 megawatts. This capacity is generally more likely to operate on-peak than central thermal plants are: even wind, 5.8 GW of the offered 20.3 GW, is quite reliable on hot summer afternoons.
12. Counting electricity at its heat value of 3.6 megajoules per kilowatt hour. See H. R. Heede, "A preliminary analysis of federal energy subsidies in FY1984," testimony before the U.S. House of Representatives, Commerce Committee, Subcommittee on Energy Conservation and Power, 20 June 1985, available from the author. Heede's data show that fiscal year 1984 federal energy subsidies exceeded $46 billion, and that $1 of subsidy to efficiency and renewables yielded 80 times as much energy as $1 of subsidy to nuclear power.